

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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Technical Analysis of the August 14, 2003, Blackout: *What Happened, Why, and What Did We Learn?*

**Report to the NERC Board of Trustees
by the NERC Steering Group**

July 13, 2004

Acknowledgements

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NERC acknowledges the strong leadership of the Steering Group, which guided the investigation on behalf of NERC. The Steering Group members are:

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David Hilt, NERC Vice President-Compliance, directed the NERC investigation. He was assisted by Gerry Cauley, Director-Standards.

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I. Introduction

On August 14, 2003, just after 4 p.m. Eastern Daylight Time (EDT),¹ the North American power grid experienced its largest blackout ever. The blackout affected an estimated 50 million people and more than 70,000 megawatts (MW) of electrical load in parts of Ohio, Michigan, New York, Pennsylvania, New Jersey, Connecticut, Massachusetts, Vermont, and the Canadian provinces of Ontario and Québec. Although power was successfully restored to most customers within hours, some areas in the United States did not have power for two days and parts of Ontario experienced rotating blackouts for up to two weeks.

This report looks at the conditions on the bulk electric system that existed prior to and during the blackout, and explains how the blackout occurred. The report concludes with a series of recommendations for actions that can and should be taken by the electric industry to prevent or minimize the chance of such an outage occurring in the future.

A. NERC Investigation

1. Scope of Investigation

Historically, blackouts and other significant electric system events have been investigated by the affected regional reliability councils. The NERC Disturbance Analysis Working Group would then review the regional reports and prepare its own evaluation of the broader lessons learned. The August 14 blackout was unique with regard to its magnitude and the fact that it affected three NERC regions. The scope and depth of NERC's investigation into a blackout of this magnitude was unprecedented.

Immediately following the blackout, NERC assembled a team of technical experts from across the United States and Canada to investigate exactly what happened, why it happened, and what could be done to minimize the chance of future outages. To lead this effort, NERC established a steering group of leading experts from organizations that were not directly affected by the cascading grid failure.

The scope of NERC's investigation was to determine the causes of the blackout, how to reduce the likelihood of future cascading blackouts, and how to minimize the impacts of any that do occur. NERC focused its analysis on factual and technical issues including power system operations, planning, design, protection and control, and maintenance. Because it is the responsibility of all power system operating entities to operate the electric system reliably at all times, irrespective of regulatory, economic, or market factors, the NERC investigation did not address regulatory, economic, market structure, or policy issues.

2. Support for U.S.-Canada Power System Outage Task Force

NERC's technical investigation became a critical component of the U.S.-Canada Power System Outage Task Force, a bi-national group formed to examine all aspects of the August 14 outage. The Task Force formed three working groups to investigate the electric power system, nuclear power plant, and security aspects of the blackout. The electric system working group was led by representatives from the U.S. Department of Energy, the U.S. Federal Energy Regulatory Commission, and Natural Resources Canada.

The NERC investigation provided support to the electric system working group, analyzing enormous volumes of data to determine a precise sequence of events leading to and during the cascade. The NERC

¹ All times referenced in this report have been converted to Eastern Daylight Time.

teams met regularly with representatives of the Task Force to determine why the blackout occurred and why it extended as far as it did.

In its November 19 interim report, the Task Force concluded, and NERC concurred, that the initiating causes of the blackout were 1) that FirstEnergy (FE) lost functionality of its critical monitoring tools and as a result lacked situational awareness of degraded conditions on its transmission system, 2) that FE did not adequately manage tree growth in its transmission rights-of-way, 3) that the Midwest Independent System Operator (MISO) reliability coordinator did not provide adequate diagnostic support, and 4) that coordination between the MISO and PJM reliability coordinators was ineffective. The report cited several violations of NERC reliability standards as contributing to the blackout.

After the interim report was issued, NERC continued to support the electric system working group. NERC also began to develop its own technical report and a set of recommendations to address issues identified in the investigation.

3. Investigation Organization

Before the electric system had been fully restored, NERC began to organize its investigation. NERC appointed a steering group of industry leaders with extensive executive experience, power system expertise, and objectivity. This group was asked to formulate the investigation plan and scope, and to oversee NERC's blackout investigation.

NERC's initial efforts focused on collecting system data to establish a precise sequence of events leading up to the blackout. In the initial stage of the investigation, investigators began to build a sequence of events from information that was then available from NERC regions and from reliability coordinators. To complete such a large-scale investigation, however, it quickly became apparent that additional resources were needed. The investigation was augmented with individuals from the affected areas that had knowledge of their system design, configuration, protection, and operations. Having this first-hand expertise was critical in developing the initial sequence of events. These experts were added to the investigation teams and each team was assigned to build a sequence of events for a specific geographic area. As the sequence of events became more detailed, a database was created to facilitate management of the data and to reconcile conflicting time stamps on the thousands of events that occurred in the time leading up to and during the power system failure.

The NERC Steering Group organized investigators into teams to analyze discrete events requiring specific areas of expertise, as shown in Figure I.1. To fill these teams, NERC called on industry volunteers. The number and quality of experts who answered the call was extraordinary. Many of these volunteers relocated temporarily to Princeton, New Jersey, to allow for close collaboration during the investigation. The teams dedicated long hours — often seven days per week — over several months to analyze what happened and why. The investigators operated with complete autonomy to investigate all possible causes of the blackout. The investigation methods were systematic — investigators “looked under every rock” and methodically proved or disproved each theory put forth as to why and how the blackout occurred.

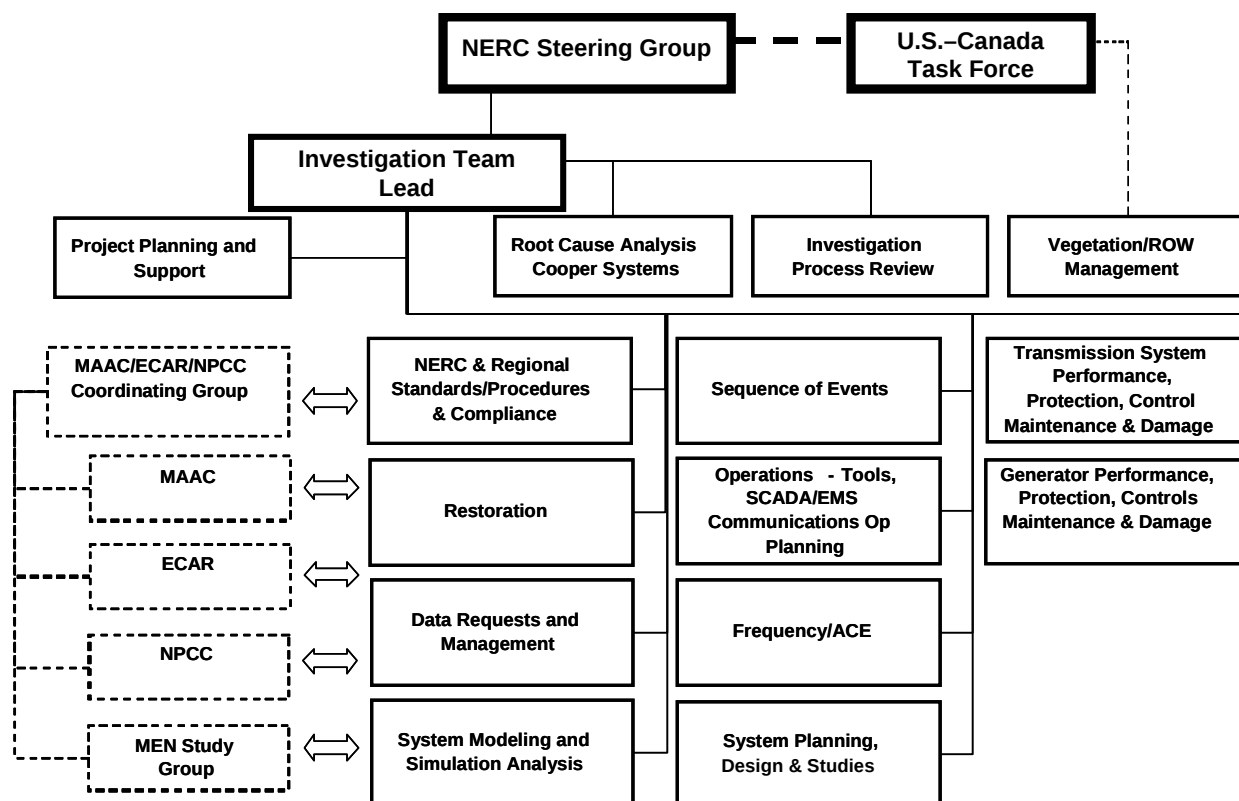


Figure I.1 — NERC Blackout Investigation Organization

4. Investigation Process

Under the guidance of the Steering Group, NERC developed a formal investigation plan. The investigation plan assigned work scopes, deliverables, and milestones for each investigation team. The major elements of the investigation process are summarized here:

- In the first days after the blackout, NERC and the reliability coordinators conferred by hotline calls to assess the status of system restoration, the continuing capacity shortage and rotating blackouts, and initial information on what had happened.
- On August 17, NERC notified all reliability coordinators and control areas in the blackout area to retain state estimator, relay, and fault recorder data from 08:00 to 17:00 on August 14. A subsequent request added event logs, one-line diagrams, and system maps to the list. On August 22, NERC issued a more substantive data request for the hours of 08:00 to 22:00 on August 14. Additional data requests were made as the investigation progressed. The response to the data requests was excellent; many entities submitted more information related to the blackout than was requested. To manage the enormous volume of data, NERC installed additional computers and a relational database, and assigned a team to catalog and manage the data.
- As part of the U.S.-Canada Power System Outage Task Force investigation and in cooperation with NERC, the U.S. Department of Energy conducted onsite interviews with operators, engineers, computer staff, supervisors, and others at all of the affected reliability coordinator and control area operating centers.
- The analysis portion of the investigation began with the development of a sequence of events. The initial focus was on the critical events leading up to the power system cascade. The task was painstakingly arduous due to the large volume of event data and the limited amount of

information that was precisely synchronized to a national time standard. Assembling the timeline to the level of accuracy needed for the remaining areas of investigation was analogous to completing a jigsaw puzzle with thousands of unique interlocking pieces. The initial sequence of events was published on September 12, 2003.

- NERC established teams to analyze different aspects of the blackout. Each team was assigned a scope and the necessary experts to complete its mission. The teams interacted frequently with investigation leaders and with the co-chairs of the electric system working group.
- A cornerstone of the investigation was a root cause analysis sponsored by the U.S. Department of Energy and facilitated by a contractor with expertise in that area. This systematic approach served to focus the investigation teams on proving the causes of the blackout based on verified facts. The work of these investigation teams was based on a) gathering data; b) verifying facts through multiple, independent sources; c) performing analysis and simulations with the data; and d) conducting an exhaustive forensic analysis of the causes of the blackout.
- NERC assisted the U.S.-Canada Power System Outage Task Force in conducting a series of information-gathering meetings on August 22, September 8–9, and October 1–3. These meetings were open only to invited entities; each meeting was recorded, and a transcription prepared for later use by investigators. The first meeting focused on assessing what was known about the blackout sequence and its causes, and identifying additional information requirements. The second meeting focused on technical issues framed around a set of questions directed to each entity operating in the blackout area. The third meeting focused on verifying detailed information to support the root cause analysis. Participation was narrowed to include only the investigators and representatives of the FirstEnergy and AEP control areas, and the Midwest Independent Transmission System Operator (MISO) and PJM reliability coordinators.
- On October 15, 2003, NERC issued a letter to all reliability coordinators and system operating entities that required them to address some of the key issues arising from the investigation.
- On November 19, 2003, the U.S.-Canada Power System Outage Task Force issued its interim report on the events and causes of the August 14 blackout. The report was developed in collaboration with the NERC investigation and NERC concurred with the report's findings.
- The second phase of the blackout investigation began after the interim report was released. For NERC, the second phase focused on two areas. First, NERC continued to analyze why the cascade started and spread as far as it did. The results of this analysis were incorporated into this report and also provided to the U.S.-Canada Power System Outage Task Force for inclusion in its final report, which was issued on April 5, 2004. NERC also began, independently of the Task Force, to develop an initial set of recommendations to minimize the risk and mitigate the impacts of possible future cascading failures. These recommendations were approved by the NERC Board of Trustees on February 10, 2004.

5. Coordination with NERC Regions

The NERC regions and the regional transmission organizations (RTOs) within these regions played an important role in the NERC investigation; these entities also conducted their own analyses of the events that occurred within their regions. The regions provided a means to identify all facility owners and to collect the necessary data. Regular conference calls were held to coordinate the NERC and regional investigations and share results.

The NERC regions provided expert resources for system modeling and simulation and other aspects of the analysis. The investigation relied on the multi-regional MAAC-ECAR-NPCC Operations Studies

Working Group, which had developed summer loading models of the systems affected by the blackout. Other groups, such as the SS-38 Task Force (system dynamics data) and Major System Disturbance Task Force, provided valuable assistance to the investigation.

The restoration phase of the blackout was successful, and NERC has deferred the bulk of the analysis of system restoration efforts to the regions, RTOs, and operating entities. Evaluation of the restoration is a significant effort that requires analyzing the effectiveness of thousands of actions against local and regional restoration plans. The results of this analysis will be consolidated by NERC and reported at a future date.

6. Ongoing Dynamic Investigation

The electrical dynamics of the blackout warrant unprecedented detailed technical analysis. The MAAC-ECAR-NPCC Major System Disturbance Task Force continues to analyze the dynamic swings in voltage, power flows, and other events captured by high-speed disturbance recorders. The results of that work will be published as they become available.

B. Report Overview

The report begins by telling a detailed story of the blackout, outlining what happened, and why. This portion of the report is organized into three sections: Section II describes system conditions on August 14 prior to the blackout, Section III describes events in northeastern Ohio that triggered the start of an uncontrolled cascade of the power system, and Section IV describes the ensuing cascade. The report concludes in Section V with a summary of the causes of the blackout, contributing factors, and other deficiencies. This section also provides a set of NERC recommendations. The majority of these recommendations were approved on February 10, 2004; however, several new recommendations have been added. Supplemental reports developed by investigation teams are under development and will be available in phase II of this report.

A report on vegetation management issues developed by the U.S.-Canada Power System Outage Task Force is an additional reference that complements this report.

C. Key Entities Affected by the August 14 Blackout

1. Electric Systems Affected by the Blackout

The August 14 blackout affected the northeastern portion of the Eastern Interconnection, covering portions of three NERC regions. The blackout affected electric systems in northern Ohio, eastern Michigan, northern Pennsylvania and New Jersey, much of New York and Ontario. To a lesser extent, Massachusetts, Connecticut, Vermont, and Québec were impacted. The areas affected by the August 14 blackout are shown in Figure I.2.

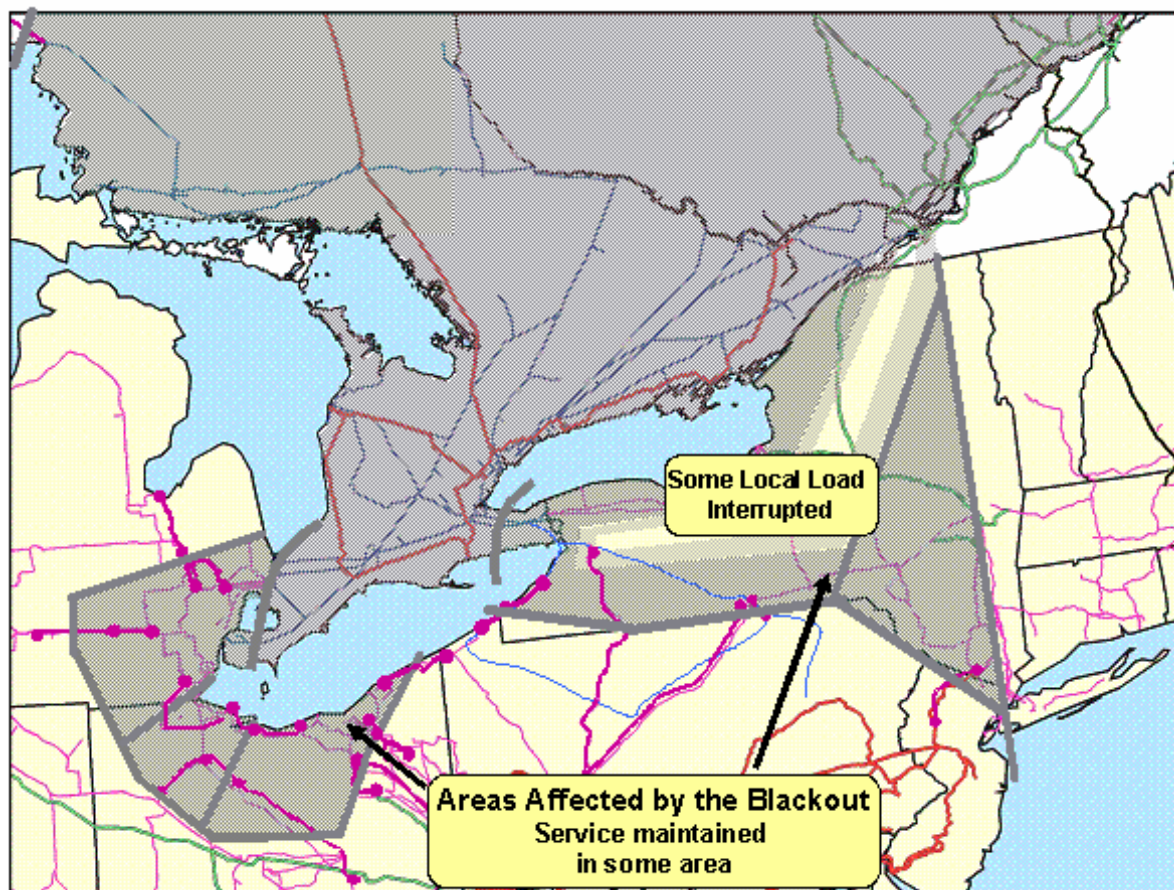


Figure I.2 — Area Affected by the Blackout

The power system in Ontario is operated by the Independent System Operator (IMO). The New York system is operated by the New York Independent System Operator (NYISO). The mid-Atlantic area, including the northern Pennsylvania and northern New Jersey areas affected by the blackout, is operated by the PJM Interconnection, LLC (PJM). Each of these entities operates an electricity market in their respective area and is responsible for reliability of the bulk electric system in that area. Each is designated as both the system operator and the reliability coordinator for their respective area.

In the Midwest, several dozen utilities operate their own systems in their franchise territory. Reliability oversight in this region is provided by two reliability coordinators, the Midwest Independent Transmission System Operator (MISO) and PJM.

New England, which is operated by the New England Independent System Operator (ISO-NE), was in the portion of the Eastern Interconnection that became separated, but was able to stabilize its generation and load with minimal loss, except for the southwest portion of Connecticut, which blacked out with New York City. Nova Scotia and Newfoundland were also not impacted severely. Hydro-Québec operates the electric system in Québec and was mostly unaffected by the blackout because this system is operated asynchronously from the rest of the interconnection.

Several of the key players involved in the blackout are described in more detail below.

2. FirstEnergy Corporation

FirstEnergy Corporation (FE) is the fifth largest electric utility in the United States. FE serves 4.4 million electric customers in a 36,100 square mile service territory covering parts of Ohio, Pennsylvania, and New Jersey. FE operates 11,502 miles of transmission lines, and has 84 ties with 13 other electric systems.

FE comprises seven operating companies (Figure I.3). Four of these companies, Ohio Edison, Toledo Edison, The Illuminating Company, and Penn Power, operate in the ECAR region; MISO serves as their reliability coordinator. These four companies now operate as one integrated control area managed by FE. The remaining three FE companies, Penelec, Met-Ed, and Jersey Central Power & Light, are in the MAAC region and PJM is their reliability coordinator. This report addresses the FE operations in northern Ohio, within ECAR and the MISO reliability coordinator footprint.

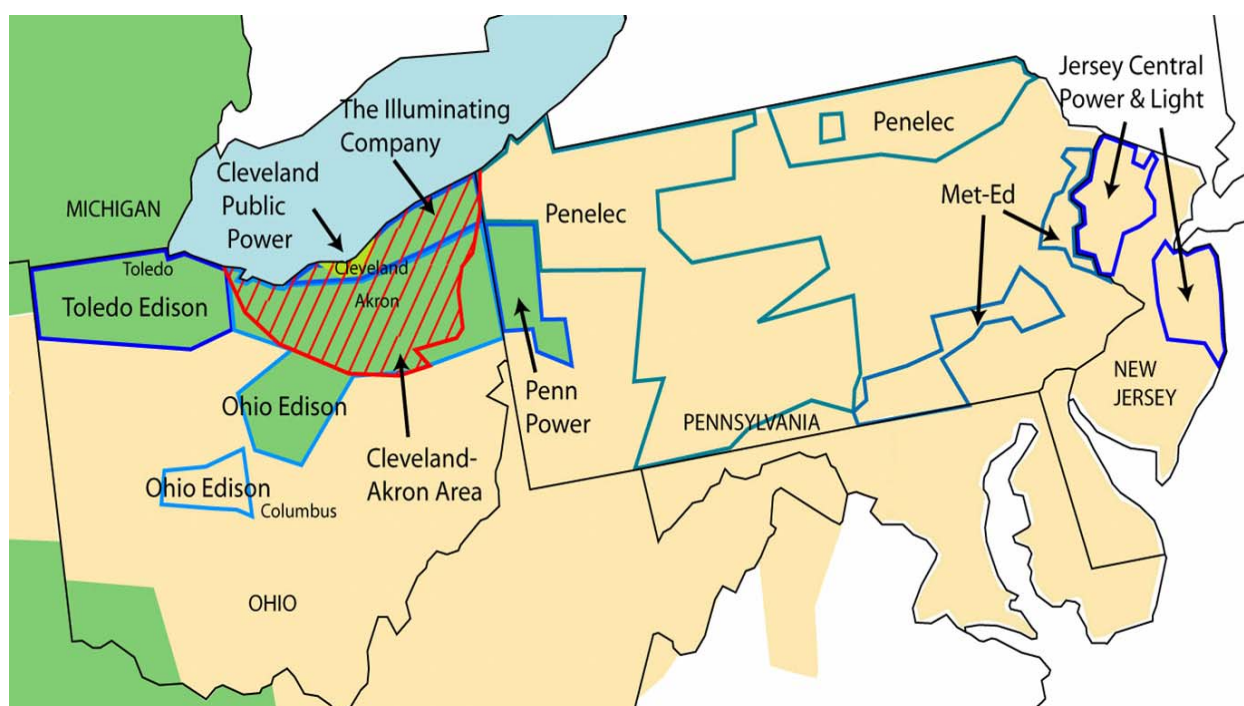


Figure I.3 — FE Operating Areas

FE operates several control centers in Ohio that perform different functions. The first is the unregulated Generation Management System (GMS), which is located in a separate facility from the transmission system operations center. The GMS handles the unregulated generation portion of the business, including Automatic Generation Control (AGC) for the FE units, managing wholesale transactions, determining fuel options for their generators, and managing ancillary services. On August 14, the GMS control center was responsible for calling on automatic reserve sharing to replace the 612 MW lost when the Eastlake Unit 5 tripped at 13:31.

The second FE control center houses the Energy Management System (EMS). The EMS control center is charged with monitoring the operation and reliability of the FE control area and is managed by a director of transmission operation services. Two main groups report to the director. The first group is responsible for real-time operations and the second is responsible for transmission operations planning support. The operations planning group has several dispatchers who perform day-ahead studies in a room across the hall from the control room.

The real-time operations group is divided into two areas: control area operators and transmission operators. Each area has two positions that are staffed 24 hours a day. A supervisor with responsibility for both areas is always present. The supervisors work 8-hour shifts (7:00–15:00, 15:00–21:00, and 21:00–7:00), while the other operators work 12-hour shifts (6:00–18:00 and 18:00–6:00). The transmission operators are in the main control room, the control area operators are in a separate room.

Within the main control room there are two desks, or consoles, for the transmission operators: the Western Desk, which oversees the western portion of the system, and the Eastern Desk, which oversees the eastern portion of the system. There is also a desk for the supervisor in the back of the room. There are other desks for operators who are performing relief duty.

In addition to the EMS control center, FE maintains several regional control centers. These satellite operating centers are responsible for monitoring the 34.5-kV and 23-kV distribution systems. These remote consoles are part of the GE/Harris EMS system discussed later in this report, and represent some of the remote console failures that occurred.

3. MISO

The Midwest Independent Transmission System Operator (MISO) is the reliability coordinator for a region that covers more than one million square miles, stretching from Manitoba, Canada, in the north to Kentucky in the south; from Montana in the west to western Pennsylvania in the east. Reliability coordination is provided by two offices, one in Minnesota, and the other at the MISO headquarters in Carmel, Indiana. MISO provides reliability coordination for 35 control areas, most of which are members of MISO.

MISO became the reliability coordinator for FirstEnergy on February 1, 2003, when the ECAR-MET reliability coordinator office operated by AEP became part of PJM. FirstEnergy became a full member of MISO on October 1, 2003, six weeks after the blackout.

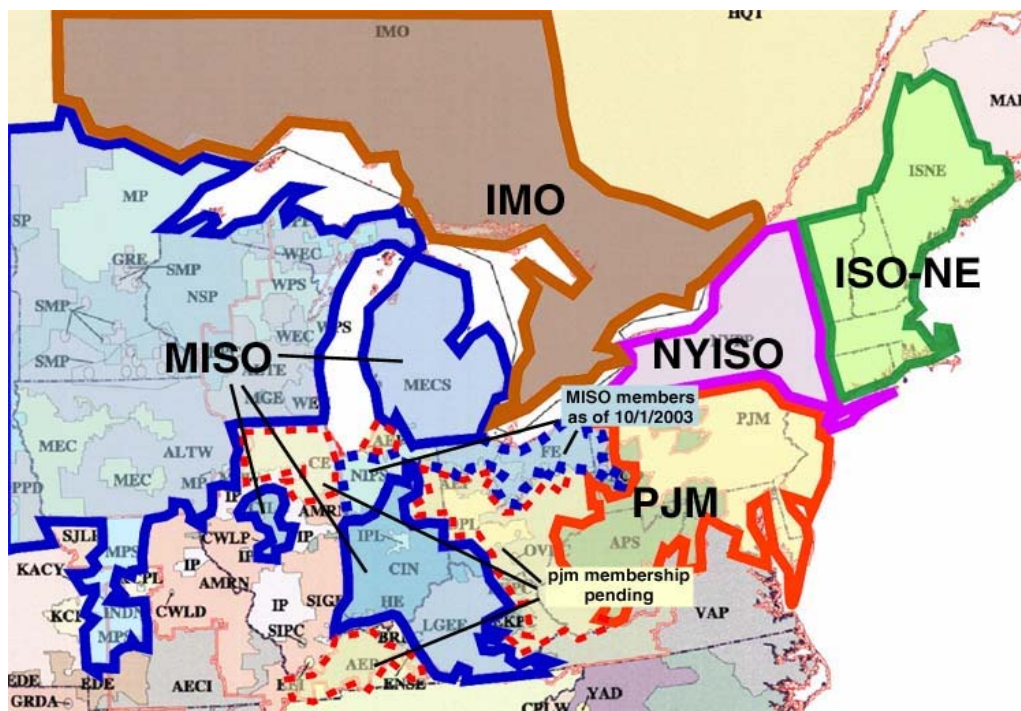


Figure I.4 — Midwest Reliability Coordinators

4. AEP

American Electric Power (AEP), based in Columbus, Ohio, owns and operates more than 80 generating stations with more than 42,000 MW of generating capacity in the United States and international markets. AEP is one of the largest electric utilities in the United States, with more than five million customers linked to AEP's 11-state electricity transmission and distribution grid. AEP's 197,500 square mile service territory includes portions of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. AEP operates approximately 39,000 miles of electric transmission lines. AEP operates the control area in Ohio just south of the FE system.

AEP system operations functions are divided into two groups: transmission and control area operations. AEP transmission dispatchers issue clearances, perform restoration after an outage, and conduct other operations such as tap changing and capacitor bank switching. They monitor all system parameters, including voltage. AEP control area operators monitor ACE, maintain contact with the PJM reliability coordinator, implement transaction schedules, watch conditions on critical flowgates, implement the NERC Transmission Loading Relief (TLR) process, and direct generator voltage schedules. AEP maintains and operates an energy management system complete with a state estimator and on-line contingency analysis that runs every five minutes.

5. PJM Interconnection, LLC

The PJM Interconnection, LLC (PJM) is AEP's reliability coordinator. PJM's reliability coordination activity is centered in its Valley Forge, Pennsylvania, headquarters with two operating centers, one in Valley Forge and one in Greensburg, Pennsylvania. There are two open video/audio live links between the west control center in Greensburg and the east control center in Valley Forge that provide for connectivity and presence between the two control centers. In training, operators are moved between all of the desks in Valley Forge and Greensburg.

PJM is also an independent system operator. PJM recently expanded its footprint to include control areas and transmission operators within MAIN and ECAR into an area it has designated as PJM-West. In PJM-East, the original PJM power pool, PJM is both the control area operator and reliability coordinator for ten utilities whose transmission systems span the Mid-Atlantic region of New Jersey, most of Pennsylvania, Delaware, Maryland, West Virginia, Ohio, Virginia, and the District of Columbia. At the time of the blackout, the PJM-West facility was the reliability coordinator desk for several control areas (Commonwealth Edison-Exelon, AEP, Duquesne Light, Dayton Power and Light, and Ohio Valley Electric Cooperative) and four generation-only control areas (Duke Energy's Washington County (Ohio) facility, Duke's Lawrence County/Hanging Rock (Ohio) facility, Allegheny Energy's Buchanan (West Virginia) facility, and Allegheny Energy's Lincoln Energy Center (Illinois) facility).

6. ECAR

The East Central Area Reliability Coordination Agreement (ECAR) is one of the ten NERC regional reliability councils. ECAR was established in 1967 as the forum to address matters related to the reliability of interconnected bulk electric systems in the east central part of the United States. ECAR members maintain reliability by coordinating the planning and operation of the members' generation and transmission facilities. ECAR membership includes 29 major electricity suppliers located in nine states serving more than 36 million people. The FE and AEP systems of interest in Ohio are located within ECAR.

ECAR is responsible for monitoring its members for compliance with NERC operating policies and planning standards. ECAR is also responsible for coordinating system studies conducted to assess the adequacy and reliability of its member systems.

II. Conditions Prior to the Start of the Blackout Sequence

The electricity industry has developed and codified a set of mutually reinforcing reliability standards and practices to ensure that system operators are prepared to deal with unexpected system events. The basic assumption underlying these standards and practices is that power system elements will fail or become unavailable in unpredictable ways. The basic principle of reliability management is that “operators must operate to maintain the security of the system they have available.”

Sound reliability management is geared toward ensuring the system will continue to operate safely following the unexpected loss of any element, such as a major generating or transmission facility. Therefore, it is important to emphasize that establishing whether conditions on the system were normal or unusual prior to and on August 14 would not in either case alleviate the responsibilities and actions expected of the power system operators, who are charged with ensuring reliability.

In terms of day-ahead planning, system operators must analyze the system and adjust the planned outages of generators and transmission lines or scheduled electricity transactions, so that if a facility was lost unexpectedly, the system operators would still be able to operate the remaining system within safe limits. In terms of real-time operations, this means that the system must be operated at all times to be able to withstand the loss of any single facility and still remain within thermal, voltage, and stability limits. If a facility is lost unexpectedly, system operators must take necessary actions to ensure that the remaining system is able to withstand the loss of yet another key element and still operate within safe limits. Actions system operators may take include adjusting the outputs of generators, curtailing electricity transactions, curtailing interruptible load, and shedding firm customer load to reduce electricity demand to a level that matches what the system is able to deliver safely. These practices have been designed to maintain a functional and reliable grid, regardless of whether actual operating conditions are normal.

A. Summary of System Conditions on August 14, 2003

This section reviews the status of the northeastern portion of the Eastern Interconnection prior to 15:05 on August 14. Analysis was conducted to determine whether system conditions at that time were in some way unusual and might have contributed to the initiation of the blackout.

Using steady-state (power flow) analysis, investigators found that at 15:05, immediately prior to the tripping of FE Chamberlin-Harding 345-kV transmission line, the system was able to continue to operate reliably following the occurrence of any of more than 800 identified system contingencies, including the loss of the Chamberlin-Harding line. In other words, at 15:05 on August 14, 2003, the system was being operated within defined steady-state limits.

Low voltages were found in the Cleveland-Akron area operated by FE on August 14 prior to the blackout. These voltages placed the system at risk for voltage collapse. However, it can be said with certainty that low voltage or voltage collapse did not cause the August 14 blackout. P-Q and V-Q analysis by investigators determined that the FE system in northeastern Ohio was near a voltage collapse, but that events required to initiate a voltage collapse did not occur.

Investigators analyzed externalities that could have had adverse effects on the FE system in northeastern Ohio and determined that none of them caused the blackout. August 14 was warm in the Midwest and Northeast. Temperatures were above normal and there was very little wind, the weather was typical of a warm summer day. The warm weather caused electrical demand in northeastern Ohio to be high, but electrical demand was not close to a record level. Voltages were sagging in the Cleveland-Akron area

due to a shortage of reactive power resources and the heavy air-conditioning loads, causing the FE system in that area to approach a voltage collapse condition.

Investigators also analyzed the interregional power transfers occurring on August 14 and determined that transfers across the area were high, but within studied limits and less than historical values and did not cause the blackout. Frequency anomalies on the Eastern Interconnection on August 14 prior to the blackout were determined to be caused by scheduling practices and were unrelated to the blackout.

In summary, prior to the 15:05 trip of the Chamberlin-Harding 345-kV line, the power system was within the operating limits defined by FE, although it was determined that FE had not effectively studied the minimum voltage and reactive supply criteria of its system in the Cleveland-Akron area. Investigators eliminated factors such as high power flows to Canada, low voltages earlier in the day or on prior days, the unavailability of specific generators or transmission lines (either individually or in combination with one another), and frequency anomalies as causes of the blackout.

B. Electric Demand and Comparisons to Historical Levels

August 14 was a hot summer day, but not unusually so. Temperatures were above normal throughout the northeast region of the United States and in eastern Canada. Electricity demand was high due to high air-conditioning loads typical of warm days in August. However, electricity demands were below record peaks. System operators had successfully managed higher demands both earlier in the summer and in previous years. Northern Ohio was experiencing an ordinary August afternoon, with loads moderately high to serve air-conditioning demand. FE imports into its Northern Ohio service territory that afternoon peaked at 2,853 MW, causing its system to consume high levels of reactive power.

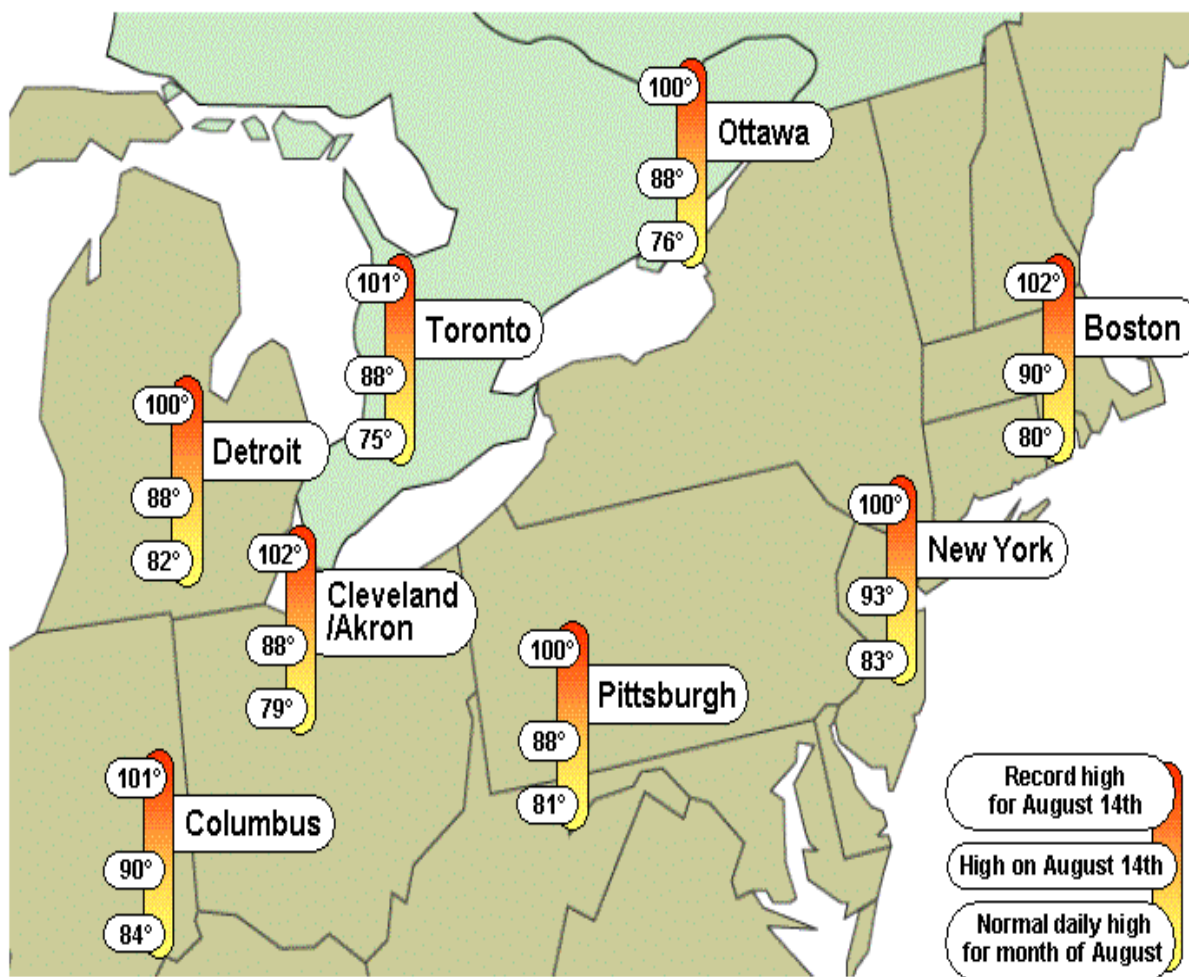


Figure II.1 — August 14 Temperatures in Northeastern United States and Eastern Canada

Table II.1 displays the peak load demands for AEP, Michigan Electric Coordinated System (MECS), FE, and PJM during the week of August 11, along with the temperatures measured at the Akron-Canton Airport. As the daily high temperature in northeastern Ohio (represented by temperatures at the Akron-Canton airport) increased from 78° F on August 11 to 87° F on August 14, the FE control area peak load demand increased by 20 percent from 10,095 MW to 12,165 MW. The loads in the surrounding systems experienced similar increases.

It is noteworthy that the FE control area peak load on August 14 was also the peak load for the summer of 2003, although it was not the all-time peak recorded for that system. That record was set on August 1, 2002, at 13,299 MW; 1,134 MW higher than on August 14, 2003. Given the correlation of load increase with ambient temperature, especially over a period of several days of warm weather, it is reasonable to assume that the load increase was due at least in part to the increased use of air conditioners. These increased air-conditioning loads lowered power factors compared to earlier in the week. These are important considerations when assessing voltage profiles, reactive reserves, and voltage stability.

Table II.1 — System Conditions for the Week August 11–14, 2003

All Load Values in MW	Monday Aug. 11	Tuesday Aug. 12	Wednesday Aug. 13	Thursday Aug. 14
Dry bulb temperature at Akron-Canton Airport	78° F	83° F	85° F	87° F
FE daily peak load in Northern Ohio (percent increase from August 11)	10,095	10,847 (7.5 percent)	11,556 (14.5 percent)	12,165 (20.5 percent)
MECS load at 14:00 (percent increase from August 11)	15,136	15,450 (2.1 percent)	17,335 (14.5 percent)	18,796 (24.2 percent)
AEP load at 14:00 (percent increase from August 11)	17,321	18,058 (4.3 percent)	18,982 (9.6 percent)	19,794 (14.3 percent)
PJM peak load (percent increase from August 11)	52,397	56,683 (8.2 percent)	58,503 (11.7 percent)	60,740 (15.9 percent)

As shown in Table II.2, FE's recorded peak electrical demands on August 14 and in prior months were well below the previously recorded peak demand.

Table II.2 — Loads on August 14 Compared to Summer 2003 and Summer 2002 Peaks

Month/Year	Actual Peak Load for Month	Date of Peak
August 2002	13,299 MW	August 1, 2002 (All-time peak)
June 2003	11,715 MW	
July 2003	11,284 MW	
August 2003	12,165 MW	August 14, 2003 (Summer 2003 Peak)

The day-ahead projections for the FE control area, as submitted to ECAR around 16:00 each afternoon that week, are shown in Table II.3. The projected peak load for August 14 was 765 MW lower than the actual FE load. FE load forecasts were low each day that week. FE forecasted that it would be a net importer over this period, peaking at 2,367 MW on August 14. Actual imports on August 14 peaked at 2,853 MW.

Table II.3 — FE Day-ahead Load Projections for Week of August 11–14, 2003

All values are in MW	Monday Aug. 11	Tuesday Aug. 12	Wednesday Aug. 13	Thursday Aug. 14
Projected Peak Load	10,300	10,200	11,000	11,400
Capacity Synchronized	10,335	10,291	10,833	10,840
Projected Import	1,698	1,800	1,818	2,367
Projected Export (to PJM)	1,378	1,378	1,278	1,278
Net Interchange (negative value is an import)	-320	-422	-540	-1,089
Spinning Reserve	355	513	373	529
Unavailable Capacity	1,100	1,144	1,263	1,433

C. Facilities out of Service

On any given day, generation and transmission capacity is unavailable; some facilities are out for routine maintenance, and others have been forced out by an unanticipated breakdown and need for repairs. August 14 was no exception.

1. Planned Generation Outages

Several key generators were out of service going into August 14.

Table II.4 — Key Generators Not Available on August 14, 2003

Generator	Rating		Reason for Outage
Davis-Besse Nuclear Unit	934 MW	481 Mvar	Prolonged NRC-ordered outage beginning on 3/22/02
Eastlake Unit 4	267 MW	150 Mvar	Forced outage on 8/13/03
Monroe Unit 1	780 MW	420 Mvar	Planned outage, taken out of service on 8/8/03
Cook Nuclear Unit 2	1,060 MW	460 Mvar	Outage began on 8/13/03
Conesville 5	400 MW	145 Mvar	Tripped at 12:05 on August 14 due to fan trip and high boiler drum pressure while returning a day early from a planned outage.

These generating units provide real and reactive power directly to the Cleveland, Toledo, and Detroit areas. Under routine practice, system operators take into account the unavailability of such units and any transmission facilities known to be out of service in the day-ahead planning studies they perform to determine the condition of the system for the next day. Knowing the status of key facilities also helps operators to determine in advance the safe electricity transfer levels for the coming day. MISO's day-ahead planning studies for August 14 took these generator outages and known transmission outages into account and determined that the regional system could be operated safely. Investigator analysis confirms that the unavailability of these generation units did not cause the blackout.

2. Transmission and Generating Unit Unplanned Outages Earlier in the Day of August 14

Several unplanned outages occurred on August 14 prior to 15:05. Around noon, several transmission lines in south-central Indiana tripped; at 13:31, the Eastlake 5 generating unit along the shore of Lake Erie tripped; at 14:02, the Stuart-Atlanta 345-kV line in southern Ohio tripped.

At 12:08, Cinergy experienced forced outages of its Columbus-Bedford 345-kV transmission line in south-central Indiana, the Bloomington-Denois Creek 230-kV transmission line, and several 138-kV lines. Although the loss of these lines caused significant voltage and facility loading problems in the Cinergy control area, they had no electrical effect on the subsequent events in northeastern Ohio leading to the blackout. The Cinergy lines remained out of service during the entire blackout (except for some reclosure attempts).

MISO operators assisted Cinergy by implementing TLR procedures to reduce flows on the transmission system in south-central Indiana. Despite having no direct electrical bearing on the blackout, these early events are of interest for three reasons:

- The Columbus-Bedford line trip was caused by a tree contact, which was the same cause of the initial line trips that later began the blackout sequence in northeastern Ohio. The Bloomington-Denois Creek 230-kV line tripped due to a downed conductor caused by a conductor sleeve failure.
- The Bloomington-Denois Creek 230-kV outage was not automatically communicated to the MISO state estimator and the missing status of this line caused a large mismatch error that stopped the MISO state estimator from operating correctly at about 12:15.

- Several hours before the start of the blackout, MISO was using the TLR procedure to offload flowgates in the Cinergy system following multiple contingencies. Although investigators believe this prior focus on TLR in Cinergy was not a distraction for later events that began in Ohio, it is indicative of the approach that was being used to address post-contingency facility overloads.

Eastlake Unit 5, located near Cleveland on the shore of Lake Erie, is a generating unit with a normal rating of 597 MW that is a major source of reactive power support for the Cleveland area. It tripped at 13:31 carrying 612 MW and 400 Mvar. The unit tripped because, as the Eastlake 5 unit operator sought to increase the unit's reactive power output in response to a request from the FE system operator, the unit's protection system detected an excitation (voltage control) system failure and tripped the unit off-line. The loss of the unit required FE to import additional power to make up for the loss of the 612 MW in the Cleveland area, made voltage management in northern Ohio more challenging, and gave FE operators less flexibility in operating their system. With two of Cleveland's generators already shut down (Davis-Besse and Eastlake 4), the loss of Eastlake 5 further depleted critical voltage support for the Cleveland-Akron area. Detailed simulation modeling reveals that the loss of Eastlake 5 was a significant factor in the outages later that afternoon; with Eastlake 5 forced out of service, transmission line loadings were notably higher but well below ratings. The Eastlake 5 unit trip is described in greater detail in Section III.

The Stuart-Atlanta 345-kV line, a Dayton Power and Light (DP&L) tie to AEP that is in the PJM-West reliability coordination area, tripped at 14:02. The line tripped as the result of a tree contact and remained out of service during the entire blackout. System modeling showed that this outage was not related electrically to subsequent events in northern Ohio that led to the blackout. However, since the line was not in MISO's footprint, MISO operators did not monitor the status of this line and did not know that it had tripped out of service. Having an incorrect status for the Stuart-Atlanta line caused MISO's state estimator to continue to operate incorrectly, even after the previously mentioned mismatch was corrected.

D. Power Transfers and Comparisons to Historical Levels

On August 14, the flow of power through the ECAR region was heavy as a result of large transfers of power from the south (Tennessee, Kentucky, Missouri, etc.) and west (Wisconsin, Minnesota, Illinois, etc.) to the north (Michigan) and east (New York). The destinations for much of the power were northern Ohio, Michigan, and Ontario, Canada.

While heavy, these transfers were not beyond previous levels or in directions not seen before. The level of imports into Ontario on August 14 was high but not unusually so. Ontario's IMO is a frequent importer of power; depending on the availability and price of generation within Ontario. IMO had safely imported similar and even larger amounts of power several times during the summers of 2003 and 2002.

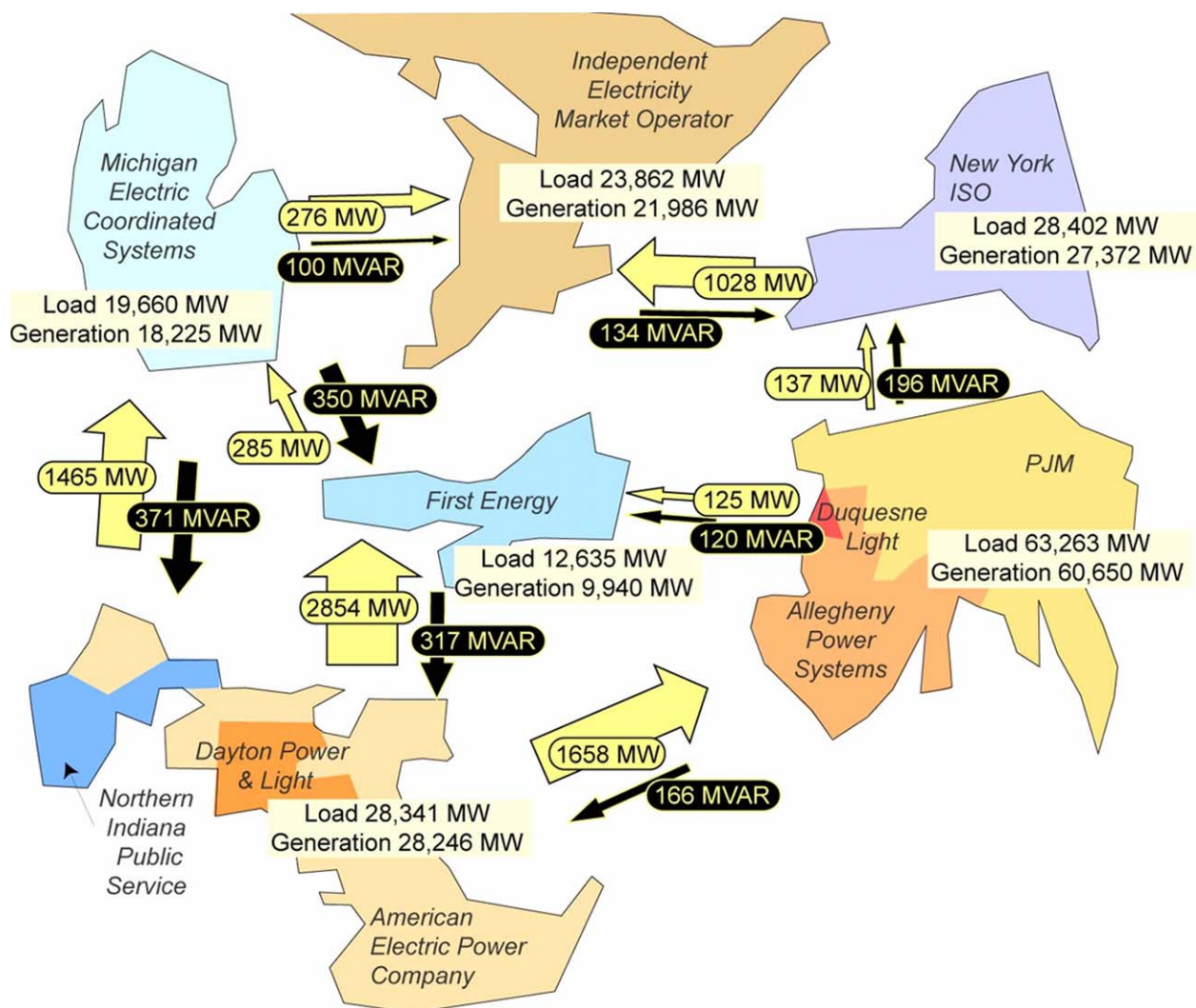


Figure II.2 — Generation, Demand, and Interregional Power Flows on August 14 at 15:05

Figure II.3 shows that the imports into the area comprising Ontario, New York, PJM, and ECAR on August 14 (shown by the red circles to be approximately 4,000 MW throughout the day) were near the peak amount of imports into that area for the period June 1 to August 13, 2003, although the August 14 imports did not exceed amounts previously seen.

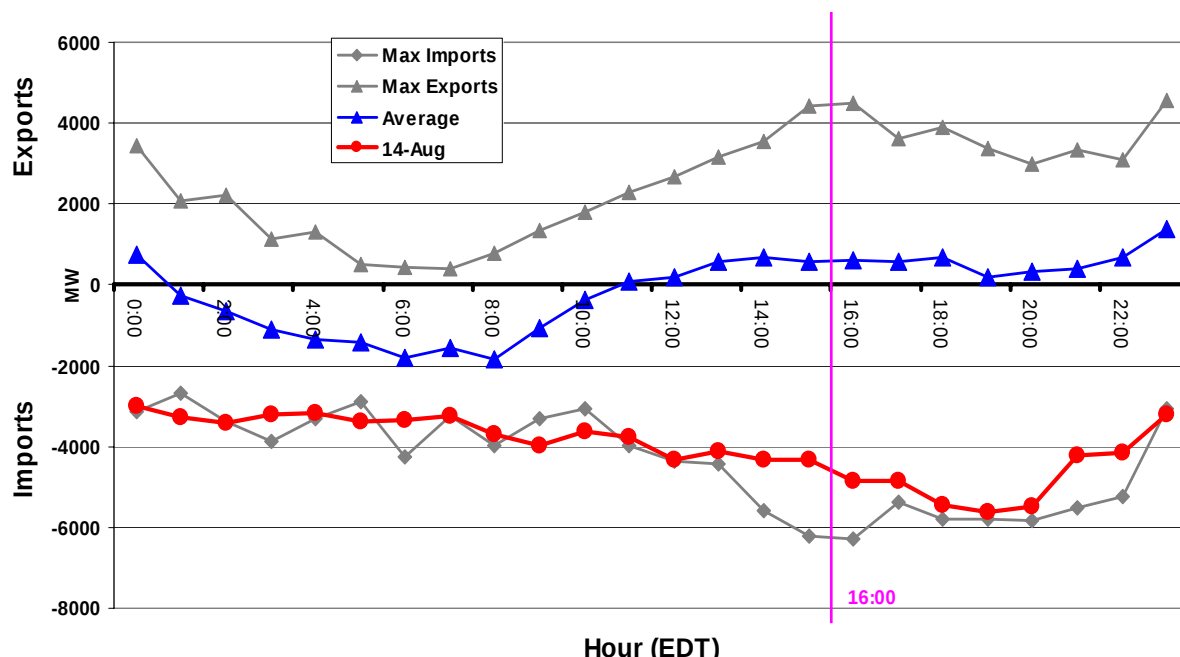


Figure II.3 — August 14, 2003, Northeast-Central Scheduled Transfers Compared to Historical Values

Figure II.4 shows the aggregated imports of the companies around Lake Erie, (MECS, IMO, FE, DLCO, NYISO, and PJM) for the peak summer days in 2002 and the days leading up to August 14, 2003. The comparison shows that the imports into the Lake Erie area were increasing in the days just prior to August 14, but that the level of these imports was lower than those recorded during the peak periods in the summer of 2002. Indeed, the import values in 2002 were about 20 percent higher than those recorded on August 14. Thus, although the imports into the Lake Erie area on August 14 were high, they were not unusually high compared to previous days in the week and were certainly lower than those recorded the previous summer.

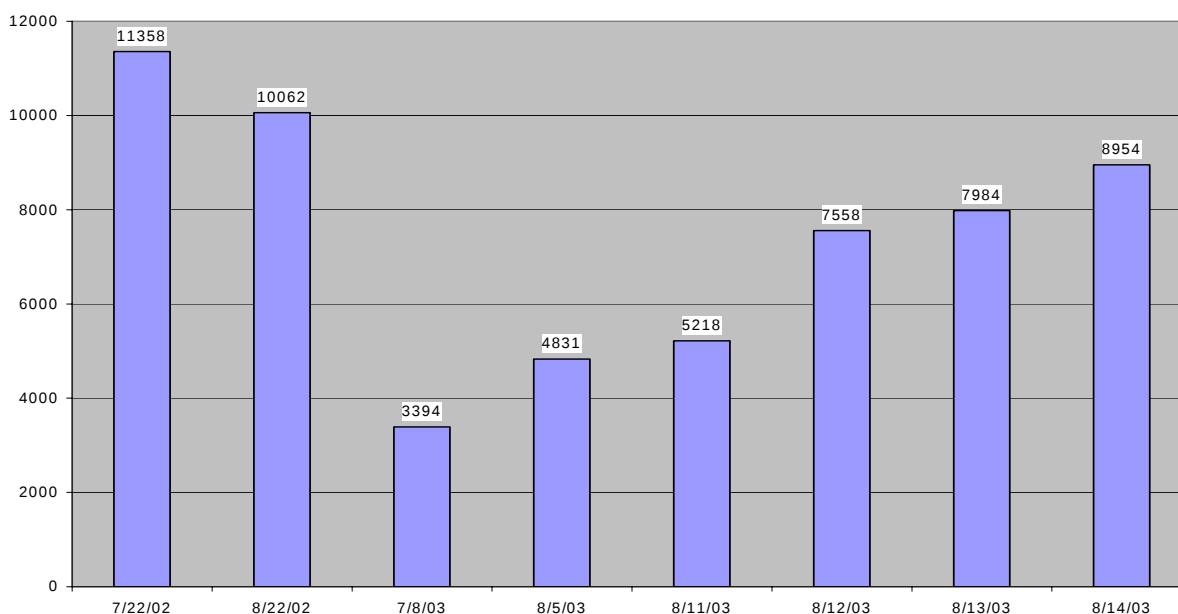


Figure II.4 — Imports for Lake Erie Systems

Another view of transfers is provided by examining the imports into IMO. Figure II.5 shows the total hourly imports into IMO for 2002 and 2003 for all days during July and August. These data show that the import levels in 2003 were generally lower compared to 2002 and that the peak import on August 14, 2003, at 2,130 MW at 14:00 was half the value recorded for the peak period in the summer of 2002.

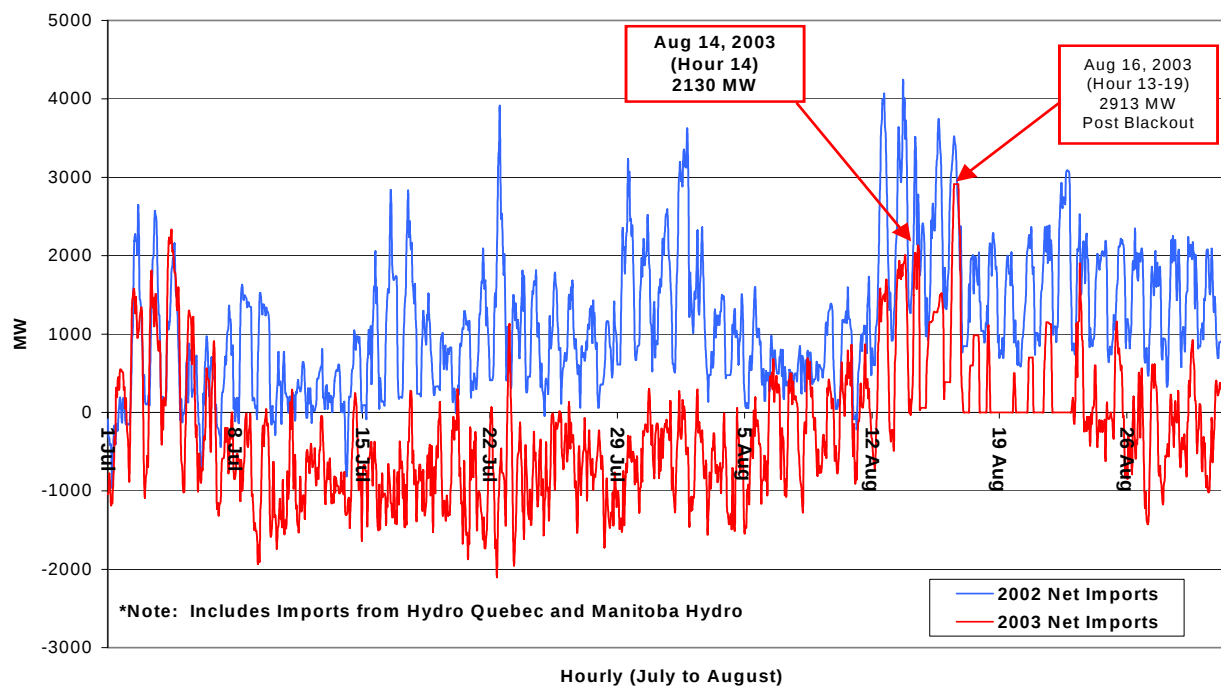


Figure II.5 — Hourly Imports into IMO

E. Voltage and Reactive Power Conditions Prior to the Blackout

1. FE Voltage Profiles

Unlike frequency, which is the same at any point in time across the interconnection, voltage varies by location and operators must monitor voltages continuously at key locations across their systems. During the days and hours leading up to the blackout, voltages were routinely depressed in a variety of locations in northern Ohio because of power transfers across the region, high air-conditioning demand, and other loads. During an interview, one FE operator stated, “some [voltage] sagging would be expected on a hot day, but on August 14 the voltages did seem unusually low.” However, as shown below in figures II.6 and II.7, actual measured voltage levels at key points on the FE transmission system on the morning of August 14 and up to 15:05 were within the range previously specified by FE as acceptable. Note, however, that most control areas in the Eastern Interconnection have set their low voltage limits at levels higher than those used by FE.

Generally speaking, voltage management can be especially challenging on hot summer days because of high transfers of power and high air-conditioning requirements, both of which increase the need for reactive power. Operators address these challenges through long-term planning, day-ahead planning, and real-time adjustments to operating equipment. On August 14, for example, investigators found that most systems in the northeastern portion of the Eastern Interconnection were implementing critical voltage procedures that are routinely used for heavy load conditions.

Figure II.6 — Representative Voltage Profile on FE System during Week of August 11

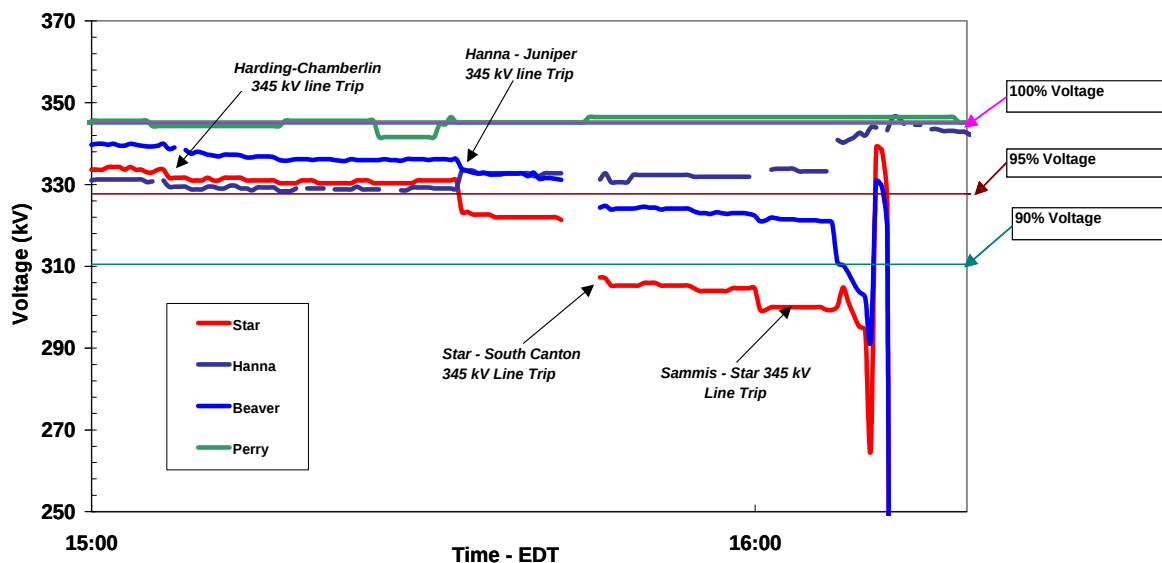
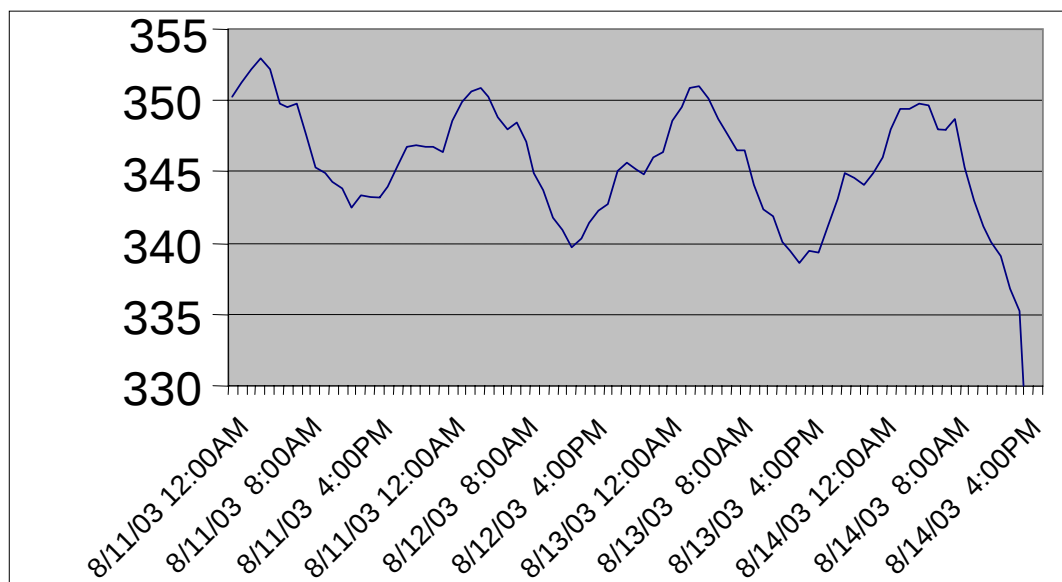


Figure II.7 — 345-kV Voltages in Northeastern Ohio on August 14, 2003

The existence of low voltages in northern Ohio is consistent with the patterns of power flow and composition of load on August 14. The power flow patterns for the region just before the Chamberlin-Harding line tripped at 15:05 show that FE was a major importer of power. Air-conditioning loads in the metropolitan areas around the southern end of Lake Erie were also consuming reactive power (Mvar). The net effect of the imports and load composition was to depress voltages in northern Ohio. Consistent with these observations, the analysis of reactive power flow shows that northern Ohio was a net importer of reactive power.

FE operators began to address voltage concerns early in the afternoon of August 14. For example, at 13:33, the FE operator requested that capacitors at Avon Substation be restored to service. From 13:13 through 13:28, the FE system operator called nine power plant operators to request additional voltage support from generators. He noted to most of them that system voltages were sagging. The operator called the following plants:

- Sammis plant at 13:13: “Could you pump up your 138 voltage?”
- West Lorain at 13:15: “Thanks. We’re starting to sag all over the system.”
- Eastlake at 13:16: “We got a way bigger load than we thought we would have. So we’re starting to sag all over the system.”
- Three calls to other plants between 13:20 and 13:23, stating to one: “We’re sagging all over the system. I need some help.” Asking another: “Can you pump up your voltage?”
- “Unit 9” at 13:24: “Could you boost your 345?” Two more at 13:26 and at 13:28: “Could you give me a few more volts?”
- Bayshore at 13:41 and Perry 1 operator at 13:43: “Give me what you can, I’m hurting.”
- 14:41 to Bayshore: “I need some help with the voltage...I’m sagging all over the system...” The response to the FE Western Desk: “We’re fresh out of vars.”

Several station operators said that they were already at or near their reactive output limits. Following the loss of Eastlake 5 at 13:31, FE operators’ concern about voltage levels was heightened. Again, while there was substantial effort to support voltages in the Ohio area, FE personnel characterized the conditions as not being unusual for a peak load day. No generators were asked to reduce their active power output to be able to produce more reactive output.

P-Q and V-Q analysis by investigators determined that the low voltages and low reactive power margins in the Cleveland-Akron area on August 14 prior to the blackout could have led to a voltage collapse. In other words, the FE system in northeastern Ohio was near a voltage collapse on August 14, although that was not the cause of the blackout.

The voltage profiles of the 345-kV network in the west-to-east and north-to-south directions were plotted from available SCADA data for selected buses. The locations of these buses are shown in Figures II.8 and II.9 respectively. They extend from Allen Junction, an FE interconnection point within ITC to the west, to Homer City in PJM to the east, and from St. Clair in ITC to the north to Cardinal-Tidd in AEP to the south.

There are three observations that can be made from these voltage profiles:

- The voltage profiles in both west-to-east and north-to-south directions display a dip at the center, with FE critical buses in the Cleveland-Akron area forming a low voltage cluster at Avon Lake, Harding, Juniper, Chamberlin, and Star.
- Voltages were observed to be higher in the portions of the FE control area outside of the Cleveland-Akron area. Voltages bordering FE in adjacent control areas were observed to be higher still. The bus voltages outside the Cleveland-Akron area are consistently higher during the period leading up to August 14.

- The bus voltages in the Cleveland-Akron area show a greater decline as the week progressed compared to buses outside this area.

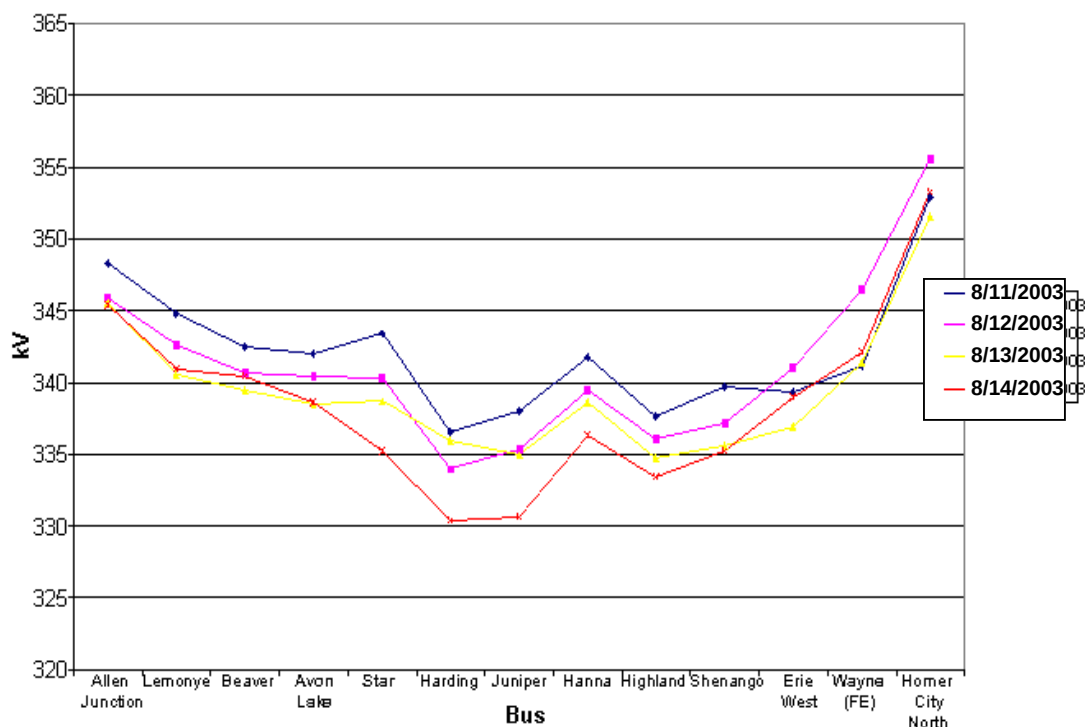


Figure II.8 — West-to-East Voltage Profile

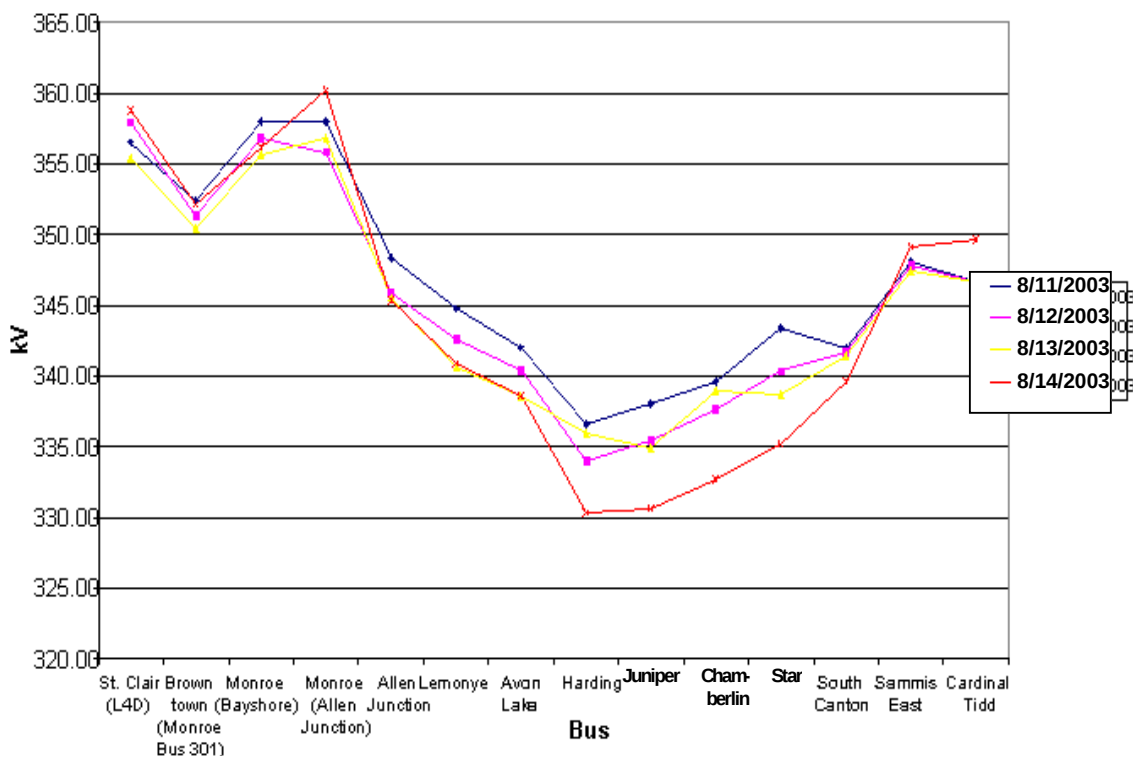


Figure II.9 — North-to-South Voltage Profile

Analysis showed that the declining voltages in the Cleveland-Akron area were strongly influenced by the increasing temperatures and loads in that area and minimally affected by transfers through FE to other systems. FE did not have sufficient reactive supply in the Cleveland-Akron area on August 14 to meet reactive power demands and maintain a safe margin from voltage collapse.

2. FE Reactive Reserves

Figure II.10 shows the actual reactive power reserves from representative generators along the Lake Erie shore and in the Cleveland-Akron area for three time periods on August 14. It also shows the reactive power reserves from representative generators in AEP, MECS, and PJM that are located in the proximity of their interconnections with FE.

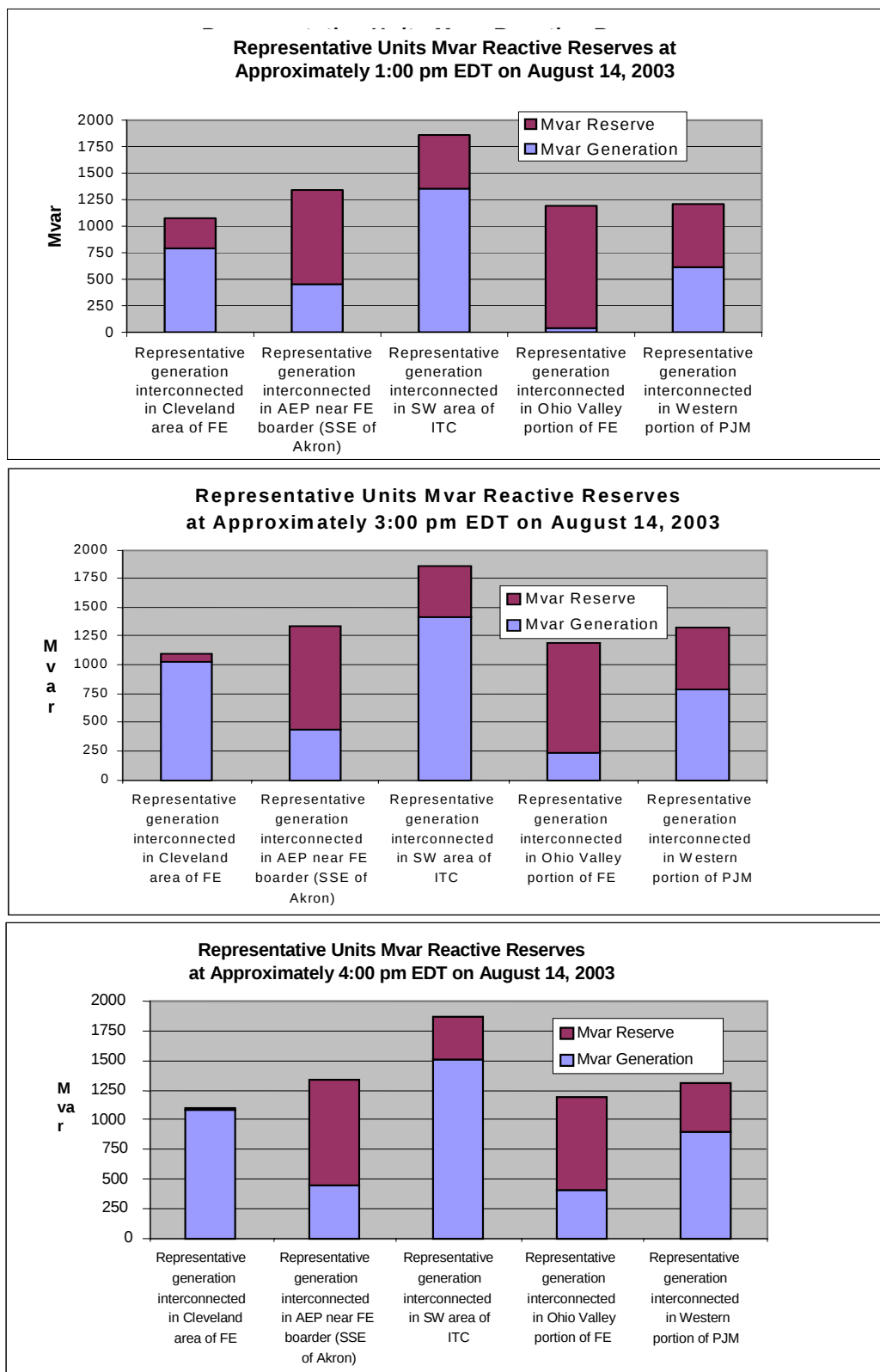


Figure II.10 — Reactive Reserves of Representative Groups of Generators on August 14, 2003

The following observations may be made:

- Reactive power reserves from the FE generators located in the Cleveland-Akron area were consistently lower than those from generators in both neighboring systems and in the southern portion of the FE system. These reserves were less than the reactive capability of the Perry nuclear generating station, the largest generating unit in the area, meaning that if the Perry unit had tripped offline, the Cleveland-Akron area would have been depleted of any reactive power reserve.
- The reactive reserves in the Cleveland-Akron area were progressively reduced as successive outages occurred on the afternoon of August 14. By 16:00, after numerous 138-kV line failures, the reserve margins in the Cleveland-Akron area were depleted.
- Generators external to this area had ample reactive margins while maintaining their scheduled voltages, but that reactive power was unable to reach the Cleveland-Akron area due to the limited ability of reactive power to flow over long distances. These included the generator group located southeast of Akron, consisting of Sammis, Beaver Valley, and Mansfield.

F. System Frequency

Figure II.11 shows a plot of the frequency for the Eastern Interconnection on August 14. As is typical, frequency is highly random within a narrow band of several one hundredths of a hertz. Prior to the blackout, frequency was within the statistical bounds of a typical day. Scheduled frequency was lowered to 59.98 at noon to conduct a time error correction. This is a routine operation. After the blackout, the frequency was high and highly variable following the loss of exports to the Northeast. Also, there appears to be a pattern relating to the times during which frequency deviations are larger.

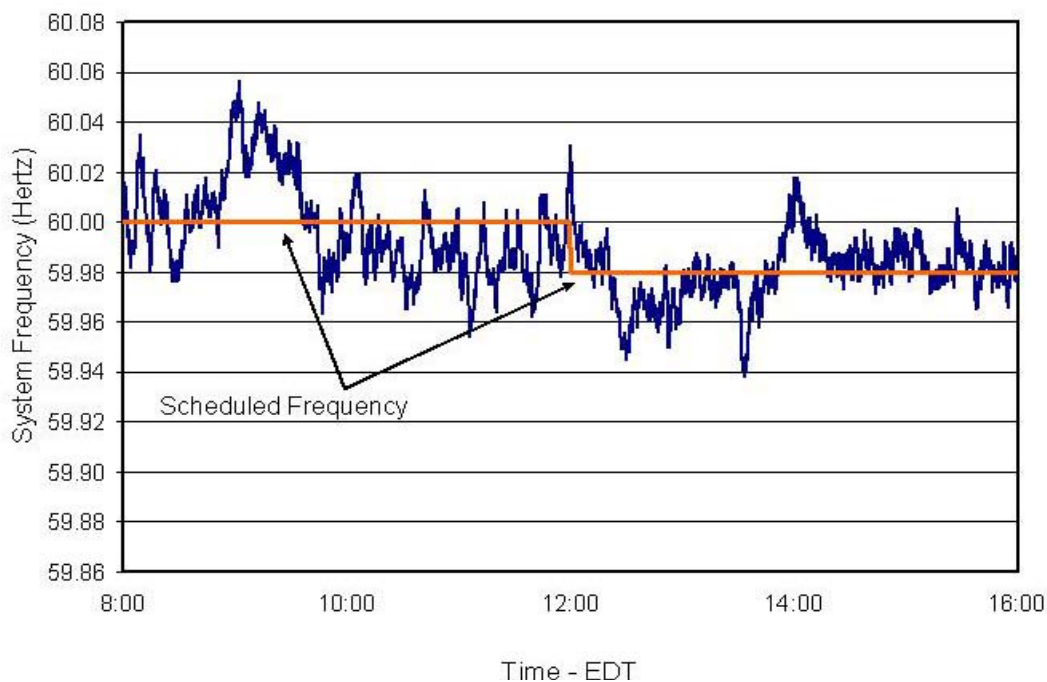


Figure II.11 — Eastern Interconnection Frequency Plot for August 14, 2003

System frequency anomalies earlier in the day on August 14 are explained by previously known interchange scheduling issues and were not a precursor to the blackout. Although frequency was

somewhat variable on August 14, it was well within the bounds of safe operating practices as outlined in NERC operating policies and consistent with historical values.

Large signals in the random oscillations of frequency were seen on August 14, but this was typical for most other days as well, indicating a need for attention to the effects of scheduling interchange on interconnection frequency. Frequency generally appeared to be running high, which is not by itself a problem, but indicates that there were insufficient resources to control frequency for the existing scheduling practices. This behavior indicates that frequency anomalies seen on August 14 prior to the blackout were caused by the ramping of generation around regular scheduling time blocks and were neither the cause of the blackout nor precursor signals of a system failure. The results of this investigation should help to analyze control performance in the future.

G. Contingency Analysis of Conditions at 15:05 EDT on August 14

A power flow base case was established for 15:05 on August 14 that encompassed the entire northern portion of the Eastern Interconnection. Investigators benchmarked the case to recorded system conditions at that time. The team started with a projected summer 2003 power flow case developed in the spring of 2003 by the regional reliability councils. The level of detail involved in this region-wide study exceeded that normally considered by individual control areas and reliability coordinators. It consisted of a detailed representation of more than 44,300 buses, 59,086 transmission lines and transformers, and 6,987 major generators across the northern United States and eastern Canada. The team then revised the summer power flow case to match recorded generation, demand, and power interchange levels among control areas at 15:05 on August 14. The benchmarking consisted of matching the calculated voltages and line flows to recorded observations at more than 1,500 locations within the grid at 15:05.

Once the base case was benchmarked, the team ran a contingency analysis that considered more than 800 possible events as points of departure from the 15:05 case. None of these contingencies were found to result in a violation of a transmission line loading or bus voltage limit prior to the trip of the Chamberlin-Harding line in the FE system. According to these simulations, at 15:05, the system was able to continue to operate safely following the occurrence of any of the tested contingencies. From an electrical standpoint, the system was being operated within steady state limits at that time. Although the system was not in a reliable state with respect to reactive power margins, that deficiency did not cause the blackout.

III. Causal Events Leading to the Power System Cascade

This section explains the major events — electrical, operational, and computer-related — leading up to and causing the blackout. The period covered in this section begins at 12:15 EDT on August 14, when missing information on the Cinergy Bloomington-Denois Creek 230-kV line initially rendered MISO's state estimator ineffective. The section ends at 16:05:57 EDT on August 14, when the Sammis-Star 345-kV transmission line tripped, signaling the transition from a local event in northeastern Ohio to the start of an uncontrolled cascade that spread through much of northeastern North America.

A. Event Summary

At 13:31, the FE Eastlake 5 generating unit tripped offline due to an exciter failure while the operator was making voltage adjustments. Had Eastlake 5 remained in service, subsequent line loadings on the 345-kV paths into Cleveland would have been slightly lower and outages due to tree contacts might have been delayed; there is even a remote possibility that the line trips might not have occurred. Loss of Eastlake 5, however, did not cause the blackout. Analysis shows that the FE system was still operating within FE-defined limits after the loss of Eastlake 5.

Shortly after 14:14, the alarm and logging system in the FE control room failed and was not restored until after the blackout. Loss of this critical control center function was a key factor in the loss of situational awareness of system conditions by the FE operators. Unknown to the operators, the alarm application failure eventually spread to a failure of multiple energy management system servers and remote consoles, substantially degrading the capability of the operators to effectively monitor and control the FE system. At 14:27, the Star-South Canton 345-kV tie line between FE and AEP opened and reclosed. When AEP operators called a few minutes later to confirm the operation, the FE operators had no indication of the operation (since the alarms were out) and denied their system had a problem. This was the first clear indication of a loss of situational awareness by the FE operators.

Between 15:05 and 15:42, three FE 345-kV transmission lines supplying the Cleveland-Akron area tripped and locked out because the lines contacted overgrown trees within their rights-of-way. At 15:05, while loaded at less than 45 percent of its rating, FE's Chamberlin-Harding 345-kV line tripped and locked out. No alarms were received in the FE control room because of the alarm processor failure, and the operators' loss of situational awareness had grown from not being aware of computer problems to not being aware of a major system problem. After 15:05, following the loss of the Chamberlin-Harding line, the power system was no longer able to sustain the next-worst contingency without overloading facilities above emergency ratings.

The loss of two more key 345-kV lines in northern Ohio due to tree contacts shifted power flows onto the underlying network of 138-kV lines. These lines were not designed to carry such large amounts of power and quickly became overloaded. Concurrently, voltages began to degrade in the Akron area. As a result of the increased loading and decaying voltages, sixteen 138-kV lines tripped sequentially over a period of 30 minutes (from 15:39 to 16:09), in what can best be described as a cascading failure of the 138-kV system in northern Ohio. Several of these line trips were due to the heavily loaded lines sagging into vegetation, distribution wires, and other underlying objects.

Loss of the 138-kV paths, along with the previous loss of the 345-kV paths into Cleveland, overloaded the remaining major path into the area: the FE Sammis-Star 345-kV line. Sammis-Star tripped at 16:05:57, signaling the beginning of an uncontrollable cascade of the power system. The trip was a pivotal point between a localized problem in northeastern Ohio and what became a wide-area cascade affecting eight states and two provinces. The loss of the heavily overloaded Sammis-Star line instantly created major and unsustainable burdens on other lines, first causing a “domino-like” sequence of line outages westward and northward across Ohio and into Michigan, and then eastward, splitting New York from Pennsylvania and New Jersey. The cascade sequence after the Sammis-Star trip is described in Section IV.

Although overgrown trees caused an unexpected rash of non-random line trips on the FE system, and FE operating personnel lost situational awareness, there could have been assistance from MISO, FE’s reliability coordinator, had it not been for lack of visual tools and computer problems there as well. The first sign of trouble came at 12:15, when MISO’s state estimator experienced an unacceptably large mismatch error between state-estimated values and measured values. The error was traced to an outage of Cinergy’s Bloomington-Denois Creek 230-kV line that was not updated in MISO’s state estimator. The line status was quickly corrected, but the MISO analyst forgot to reset the state estimator to run automatically every five minutes.

At 14:02, DP&L’s Stuart-Atlanta 345-kV line tripped and locked out due to a tree contact. By the time the failure to reset the MISO state estimator to run automatically was discovered at 14:40, the state estimator was missing data on the Stuart-Atlanta outage and, when finally reset, again failed to solve correctly. This combination of human error and ineffective updating of line status information to the MISO state estimator prevented the state estimator from operating correctly from 12:15 until 15:34. MISO’s real-time contingency analysis, which relies on state estimator input, was not operational until 16:04. During this entire time, MISO was unable to correctly identify the contingency overload that existed on the FE system after the Chamberlin-Harding line outage at 15:05, and could not recognize worsening conditions as the Hanna-Juniper and Star-South Canton lines also failed. MISO was still receiving data from FE during this period, but was not aware of the line trips.

By around 15:46, when FE, MISO, and neighboring systems had begun to realize that the FE system was in serious jeopardy, the only practical action to prevent the blackout would have been to quickly drop load. Analysis indicated that at least 1,500 to 2,500 MW of load in the Cleveland-Akron area would have had to been shed. However, no such effort was made by the FE operators. They still lacked sufficient awareness of system conditions at that time and had no effective means to shed an adequate amount of load quickly. Furthermore, the investigation found that FE had not provided system operators with the capability to manually or automatically shed that amount of load in the Cleveland area in a matter of minutes, nor did it have operational procedures in place for such an action.

B. Significant Events Prior to the Start of the Blackout

1. Eastlake Unit 5 Trips at 13:31 EDT

Eastlake Unit 5 is located in northern Ohio along the southern shore of Lake Erie. The unavailability of Eastlake 4 and Davis-Besse meant that FE had to import more energy into the Cleveland-Akron area to support its load. This also increased the importance of the Eastlake 5 and Perry 1 units as resources in that area.

Throughout the morning, the EMS operators were calling the plants to request increases in reactive power. A key conversation took place between the EMS (system control center) operator and the Eastlake Unit 5 operator at approximately 13:16 on August 14:

EMS Operator: “Hey, do you think you could help out the 345 voltage a little?”

Eastlake 5 Operator: “Buddy, I am — yeah, I’ll push it to my max max. You’re only going to get a little bit.”

EMS Operator: “That’s okay, that’s all I can ask.”

The effects of the plant operator trying to go to “max max” at 13:16 are apparent in Figure III.1. The reactive output rose above the assumed maximum for about four minutes. There is a slight step increase in the reactive output of the unit again. This increase is believed to correlate with the trip of a 138-kV capacitor bank in the FE system that field personnel were attempting to restore to service. The reactive output remains at this level for another three to four minutes and then the Automatic Voltage Regulator (AVR) tripped to manual operation and a set point that effectively brought the (gross) Mvar output of the unit to zero. When a unit at full MW load trips from AVR to manual control, the Mvar output should not be designed or set to decrease the Mvar output to zero. Normal practice is to decrease the exciter to the rated full load DC field current or a reasonable preset value. Subsequent investigation found that this unit was set incorrectly.

About four or five minutes after the Mvar output decreased to zero, the operator was increasing the terminal voltage and attempting to place the exciter back on AVR control when the excitation system tripped altogether (see Figure III.1). The unit then tripped off at 13:31:34 when the loss of excitation relay operated. Later phone transcripts indicate subsequent trouble with a pump valve at the plant that would not re-seat after the trip. As a result, the unit could not be quickly returned to service.

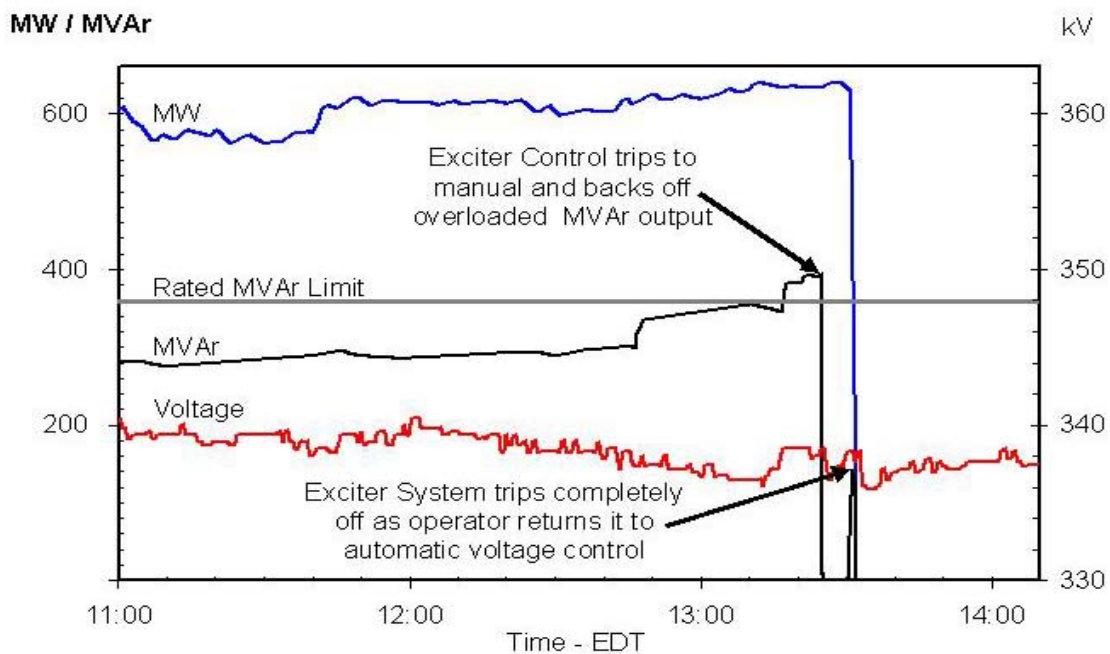


Figure III.1 — Eastlake 5 Output Prior to Trip at 13:31 EDT

The excitation system failure not only tripped the Eastlake unit 5 — a critical unit in the Cleveland area — the effort to increase Eastlake 5 voltage did not produce the desired result. Rather, the result of trying to increase the reactive output of the Eastlake 5 generating unit, once the unit tripped, was a decrease in reactive support to the Cleveland-Akron area.

At no time during the morning or early afternoon of August 14 did the FE operators indicate voltage problems or request any assistance from outside the FE control area for voltage support. FE did not report the loss of Eastlake Unit 5 to MISO. Further, MISO did not monitor system voltages; that responsibility was left to its member operating systems.

When Eastlake 5 tripped, flows caused by replacement power transfers and the associated reactive power to support these additional imports into the area contributed to higher line loadings on the paths into the Cleveland area. At 15:00, FE load was approximately 12,080 MW, and FE was importing about 2,575 MW, or 21 percent of the total load. With imports this high, FE reactive power demands, already high due to the increasing air-conditioning loads that afternoon, were using up nearly all available reactive resources.

Simulations indicate that the loss of Eastlake 5 was an electrically significant step in the sequence of events, although it was not a cause of the blackout. However, contingency analysis simulation of the conditions immediately following the loss of the Chamberlin-Harding 345-kV circuit at 15:05 shows that the system was unable to sustain the next worst contingency event without exceeding emergency ratings. In other words, with Eastlake 5 out of service, the FE system was in a first contingency limit violation after the loss of the Chamberlin-Harding 345-kV line. However, when Eastlake 5 was modeled as being in service, all contingency violations were eliminated, even after the loss of Chamberlin-Harding.

FE operators did not access contingency analysis results at any time during the day on August 14, nor did the operators routinely conduct such studies on shift. In particular, the operators did not use contingency analysis to evaluate the loss of Eastlake 5 at 13:31 to determine whether the loss of another line or generating unit would put their system at risk. FE operators also did not request or evaluate a contingency analysis after the loss of Chamberlin-Harding at 15:05 (in part because they did not know that it had tripped out of service). Thus, FE did not discover at 15:05, after the Chamberlin-Harding line trip, that their system was no longer within first contingency criteria and that operator action was needed to immediately begin correcting the situation.

FE had a state estimator that ran automatically every 30 minutes. The state estimator solution served as a base from which to perform contingency analyses. Interviews of FE personnel indicate that the contingency analysis model was likely running on August 14, but it was not consulted at any point that afternoon. FE indicated that it had experienced problems with the automatic contingency analysis operation since the system was installed in 1995. As a result, the practice was for FE operators or engineers to run contingency analysis manually as needed.

2. Stuart-Atlanta 345-kV Line Trips at 14:02 EDT

The Stuart-Atlanta 345-kV line is in the DP&L control area. After the Stuart-Atlanta line tripped, DP&L did not immediately provide an update of a change in equipment status using a standard form that posts the status change in the NERC System Data Exchange (SDX). The SDX is a database that maintains information on grid equipment status and relays that information to reliability coordinators, control areas, and the NERC IDC. The SDX was not designed as a real-time information system, and DP&L was required to update the line status in the SDX within 24 hours. MISO, however, was inappropriately using the SDX to update its real-time state estimator

model. On August 14, MISO checked the SDX to make sure that it had properly identified all available equipment and outages, but found no posting there regarding the Stuart-Atlanta outage.

At 14:02:00 the Stuart-Atlanta line tripped and locked out due to contact with a tree. Investigators determined that the conductor had contacted five 20–25 feet tall *Ailanthus* trees, burning off the tops of the trees. There was no fire reported on the ground and no fire agencies were contacted, disproving claims that the outage had been caused by ionization of the air around the conductors induced by a ground fire. Investigation modeling reveals that the loss of the Stuart-Atlanta line had no adverse electrical effect on power flows and voltages in the FE area, either immediately after its trip or later that afternoon. The Stuart-Atlanta line outage is relevant to the blackout only because it contributed to the failure of MISO's state estimator to operate effectively, and MISO was unable to provide adequate diagnostic support to FE until 16:04.

3. Star-South Canton 345-kV Line Trip and Reclose

At 14:27:16, while loaded at about 54 percent of its emergency ampere rating, the Star-South Canton 345-kV tie line (between AEP and FE) tripped and successfully reclosed. The digital fault recorder indicated a solid Phase C-to-ground fault near the FE Star station. The South Canton substation produced an alarm in AEP's control room. However, due to the FE computer alarm system failure beginning at 14:14, the line trip and reclosure at FE Star substation were not alarmed at the FE control center. The FE operators had begun to lose situational awareness of events occurring on their system as early as 14:27, when the Star-South Canton line tripped momentarily and reclosed. Figure III.2 presents the initial events: the Eastlake 5 trip, the Stuart-Atlanta trip, and the Star-South Canton trip and reclose.

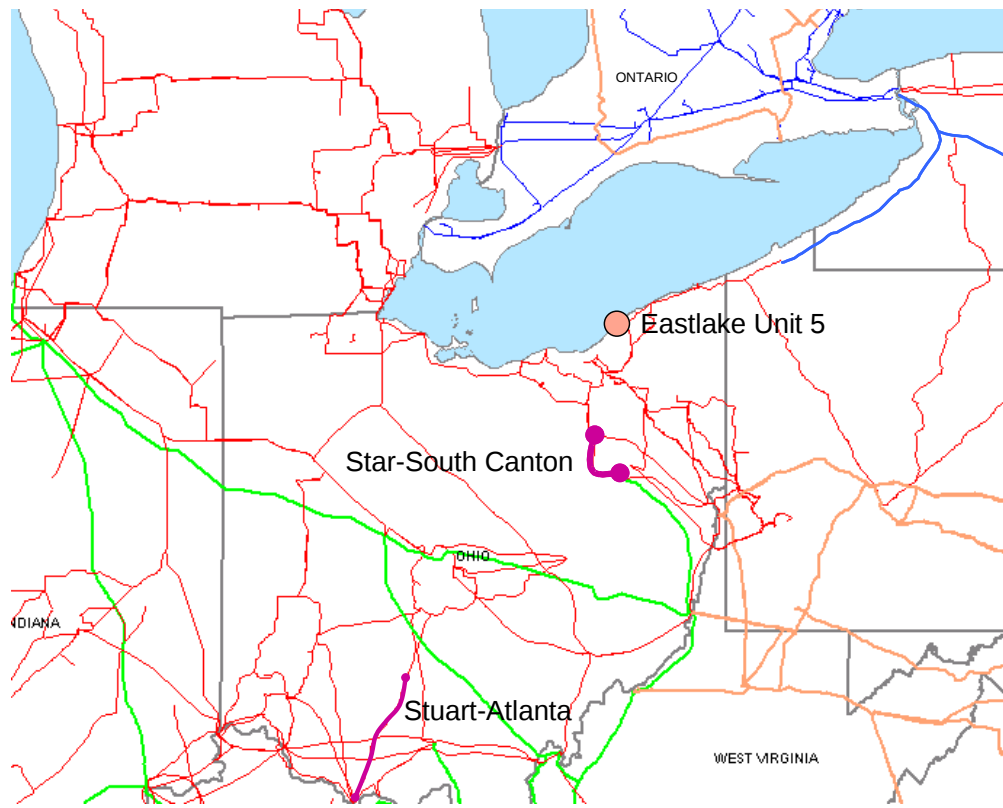


Figure III.2 — Initial Events

C. FE Computer System Failures: Loss of Situational Awareness

1. Alarm Processor Failure at 14:14 EDT

Starting around 14:14, FE control room operators lost the alarm function that provided audible and visual indications when a significant piece of equipment changed from an acceptable to problematic status. Analysis of the alarm problem performed by FE after the blackout suggests that the alarm processor essentially “stalled” while processing an alarm event. With the software unable to complete that alarm event and move to the next one, the alarm processor buffer filled and eventually overflowed. After 14:14, the FE control computer displays did not receive any further alarms, nor were any alarms being printed or posted on the EMS’s alarm logging facilities.

FE operators relied heavily on the alarm processor for situational awareness, since they did not have any other large-scale visualization tool such as a dynamic map board. The operators would have been only partially handicapped without the alarm processor, had they known it had failed. However, by not knowing that they were operating without an alarm processor, the operators did not recognize system conditions were changing and were not receptive to information received later from MISO and neighboring systems. The operators were unaware that in this situation they needed to manually, and more closely, monitor and interpret the SCADA information they were receiving.

Working under the assumption that their power system was in satisfactory condition and lacking any EMS alarms to the contrary, FE control room operators were surprised when they began receiving telephone calls from others — MISO, AEP, PJM, and FE field operations staff — who offered information on the status of FE transmission facilities that conflicted with the FE system operators’ understanding of the situation. The first hint to FE control room staff of any computer problems occurred at 14:19, when a caller and an FE control room operator discussed the fact that three sub-transmission center dial-ups had failed. At 14:25, a control room operator talked again with a caller about the failure of these three remote terminals. The next hint came at 14:32, when FE scheduling staff spoke about having made schedule changes to update the EMS pages, but that the totals did not update.

There is an entry in the FE western desk operator’s log at 14:14 referring to the loss of alarms, but it appears that entry was made after-the-fact, referring back to the time of the last known alarm.

Cause 1a²: FE had no alarm failure detection system. Although the FE alarm processor stopped functioning properly at 14:14, the computer support staff remained unaware of this failure until the second EMS server failed at 14:54, some 40 minutes later. Even at 14:54, the responding support staff understood only that all of the functions normally hosted by server H4 had failed, and did not realize that the alarm processor had failed 40 minutes earlier. Because FE had no periodic diagnostics to evaluate and report the state of the alarm processor, nothing about the eventual failure of two EMS servers would have directly alerted the support staff that the alarms had failed in an infinite loop lockup — or that the alarm processor had failed in this manner both earlier and independently of the server failure events. Even if the FE computer support staff had communicated the EMS failure to the operators (which they did not) and fully tested the critical functions after restoring the EMS (which they did not), there still would have been a minimum of 40 minutes, from 14:14 to 14:54, during which the support staff was unaware of the alarm processor failure.

² Causes appear in chronological order. Their numbering, however, corresponds to overall categorization of causes summarized in Section V.

If any operator knew of the alarm processor failure prior to 15:42, there was no evidence from the phone recordings, interview transcripts, or written logs that the problem was discussed during that time with any other control room staff or with computer support staff.

Although the alarm processing function failed, the remainder of the EMS continued to collect valid real-time status information and measurements for the FE power system, and continued to have supervisory control over the FE system. The FE control center continued to send its normal complement of information to other entities, including MISO and AEP. Thus, these other entities continued to receive accurate information about the status and condition of the FE power system, even past the point when the FE alarm processor failed. However, calls received later from these other entities did not begin to correct the FE operators' loss of situational awareness until after 15:42.

2. Remote Console Failures between 14:20 and 14:25 EDT

Between 14:20 and 14:25, several FE remote control terminals in substations ceased to operate. FE advised the investigation team that it believes this occurred because the data feeding into those terminals started "queuing" and overloading the terminals' buffers. FE system operators did not learn about the remote terminal failures until 14:36, when a technician at one of the sites noticed the terminal was not working after he came on early for the shift starting at 15:00 and called the main control room to report the problem. As remote terminals failed, each triggered an automatic page to FE computer support staff. The investigation team has not determined why some terminals failed whereas others did not. Transcripts indicate that data links to the remote sites were down as well.

3. FE EMS Server Failures

The FE EMS system includes several server nodes that perform the advanced EMS applications. Although any one of them can host all of the functions, normal FE system configuration is to have several host subsets of applications, with one server remaining in a "hot-standby" mode as a backup to the other servers, should any fail. At 14:41, the primary server hosting the EMS alarm processing application failed, due either to the stalling of the alarm application, the "queuing" to the remote terminals, or some combination of the two. Following pre-programmed instructions, the alarm system application and all other EMS software running on the first server automatically transferred ("failed-over") onto the back-up server. However, because the alarm application moved intact onto the back-up while still stalled and ineffective, the back-up server failed 13 minutes later, at 14:54. Accordingly, all of the EMS applications on these two servers stopped running.

The concurrent loss of two EMS servers apparently caused several new problems for the FE EMS and the system operators using it. Tests run during FE's after-the-fact analysis of the alarm failure event indicate that a concurrent absence of these servers can significantly slow down the rate at which the EMS refreshes displays on operators' computer consoles. Thus, at times on August 14, operator screen refresh rates, normally one-to-three seconds, slowed to as long as 59 seconds per screen. Since FE operators have numerous information screen options, and one or more screens are commonly "nested" as sub-screens from one or more top level screens, the operators' primary tool for observing system conditions slowed to a frustrating crawl. This situation likely occurred between 14:54 and 15:08, when both servers failed, and again between

15:46 and 15:59, while FE computer support personnel attempted a “warm reboot” of both servers to remedy the alarm problem.³

Loss of the first server caused an auto-page to be issued to alert the FE EMS computer support personnel to the problem. When the back-up server failed, it too sent an auto-page to FE computer support staff. At 15:08, the support staff completed a warm reboot. Although the FE computer support staff should have been aware that concurrent loss of its servers would mean the loss of alarm processing on the EMS, the investigation team has found no indication that the IT staff informed the control room staff either when they began work on the servers at 14:54 or when they completed the primary server restart at 15:08. At 15:42, a member of the computer support staff was told of the alarm problem by a control room operator. FE has stated to investigators that their computer support staff had been unaware before then that the alarm processing sub-system of the EMS was not working.

Startup diagnostics monitored during that warm reboot verified that the computer and all expected processes were running. Accordingly, the FE computer support staff believed that they had successfully restarted the node and all the processes it was hosting. However, although the server and its applications were again running, the alarm system remained frozen and non-functional, even on the restarted computer. The computer support staff did not confirm with the control room operators that the alarm system was again working properly.

Another casualty of the loss of both servers was the Automatic Generation Control (AGC) function hosted on those computers. Loss of AGC meant that FE operators could not manage affiliated power plants on pre-set programs to respond automatically to meet FE system load and interchange obligations. Although the AGC did not

Cause 1b: FE computer support staff did not effectively communicate the loss of alarm functionality to the FE system operators after the alarm processor failed at 14:14, nor did they have a formal procedure to do so. Knowing the alarm processor had failed would have provided FE operators the opportunity to detect the Chamberlin-Harding line outage shortly after 15:05 using supervisory displays still available in their energy management system. Knowledge of the Chamberlin-Harding line outage would have enabled FE operators to recognize worsening conditions on the FE system and to consider manually reclosing the Chamberlin-Harding line as an emergency action after subsequent outages of the Hanna-Juniper and Star-South Canton 345-kV lines. Knowledge of the alarm processor failure would have allowed the FE operators to be more receptive to information being received from MISO and neighboring systems regarding degrading conditions on the FE system. This knowledge would also have allowed FE operators to warn MISO and neighboring systems of the loss of a critical monitoring function in the FE control center computers, putting them on alert to more closely monitor conditions on the FE system, although there is not a specific procedure requiring FE to warn MISO of a loss of a critical control center function. The FE operators were complicit in this deficiency by not recognizing the alarm processor failure existed, although no new alarms were received by the operators after 14:14. A period of more than 90 minutes elapsed before the operators began to suspect a loss of the alarm processor, a period in which, on a typical day, scores of routine alarms would be expected to print to the alarm logger.

³ A cold reboot of the XA21 system is one in which all nodes (computers, consoles, etc.) of the system are shut down and then restarted. Alternatively, a given XA21 node can be warm rebooted whereby only that node is shut down and restarted. A cold reboot will take significantly longer to perform than a warm one. Also, during a cold reboot, much more of the system is unavailable for use by the control room operators for visibility or control over the power system. Warm reboots are not uncommon, whereas cold reboots are rare. All reboots undertaken by FE computer support personnel on August 14 were warm reboots. A cold reboot was done in the early morning of August 15, which corrected the alarm problem.

work from 14:54 to 15:08 and again from 15:46 to 15:59 (periods when both servers were down), this loss of functionality does not appear to have had any causal effect on the blackout.

The concurrent loss of the EMS servers also caused the failure of the FE strip chart function. Numerous strip charts are visible in the FE control room, driven by the EMS computers. They show a variety of system conditions including raw ACE (Area Control Error), FE system load, and Sammis-South Canton and Star-South Canton line loadings. The chart recorders continued to scroll but, because the underlying computer system was locked up, the chart pens showed only the last valid measurement recorded, without any variation from that measurement as time progressed; i.e., the charts “flat-lined.” There is no indication that any operator noticed or reported the failed operation of the charts. The few charts fed by direct analog telemetry, rather than the EMS system, showed primarily frequency data and remained available throughout the afternoon of August 14.

Without an effective EMS, the only remaining ways to monitor system conditions would have been through telephone calls and direct analog telemetry. FE control room personnel did not realize that the alarm processing on the EMS was not working and, subsequently, did not monitor other available telemetry. Shortly after 14:14 when their EMS alarms failed, and until at least 15:42 when they began to recognize the gravity of their situation, FE operators did not understand how much of their system was being lost and did not realize the degree to which their perception of system conditions was in error, despite receiving clues via phone calls from AEP, PJM, MISO, and customers. The FE operators were not aware of line outages that occurred after the trip of Eastlake 5 at 13:31 until approximately 15:45, although they were beginning to get external input describing aspects of the system’s weakening condition. Since FE operators were not aware and did not recognize events as they were occurring, they took no actions to return the system to a reliable state. Unknowingly, they used the outdated system condition information they did have to discount information received from others about growing system problems.

4. FE EMS History

The EMS in service at the FE Ohio control center is a GE Harris (now GE Network Systems) XA21 system. It was initially brought into service in 1995. Other than the application of minor software fixes or patches typically encountered in the ongoing maintenance and support of such a system, the last major updates to this EMS were made in 1998, although more recent updates were available from the vendor. On August 14, the system was not running the most recent

Cause 1c: FE control center computer support staff did not fully test the functionality of applications, including the alarm processor, after a server failover and restore. After the FE computer support staff conducted a warm reboot of the energy management system to get the failed servers operating again, they did not conduct a sufficiently rigorous test of critical energy management system applications to determine that the alarm processor failure still existed. Full testing of all critical energy management functions after restoring the servers would have detected the alarm processor failure as early as 15:08 and would have cued the FE system operators to use an alternate means to monitor system conditions. Knowledge that the alarm processor was still failed after the server was restored would have enabled FE operators to proactively monitor system conditions, become aware of the line outages occurring on the system, and act on operational information that was received. Knowledge of the alarm processor failure would also have allowed FE operators to warn MISO and neighboring systems, assuming there was a procedure to do so, of the loss of a critical monitoring function in the FE control center computers, putting them on alert to more closely monitor conditions on the FE system.

release of the XA21 software. FE had decided well before then to replace its XA21 system with an EMS from another vendor.

FE personnel told the investigation team that the alarm processing application had failed on several occasions prior to August 14, leading to loss of the alarming of system conditions and events for FE operators. This was, however, the first time the alarm processor had failed in this particular mode in which the alarm processor completely locked up due to XA21 code errors. FE computer support personnel neither recognized nor knew how to correct the alarm processor lock-up. FE staff told investigators that it was only during a post-outage support call with GE late on August 14 that FE and GE determined that the only available course of action to correct the alarm problem was a cold reboot of the XA21 system. In interviews immediately after the blackout, FE computer support personnel indicated that they discussed a cold reboot of the XA21 system with control room operators after they were told of the alarm problem at 15:42. However, the support staff decided not to take such action because the operators considered power system conditions to be precarious and operators were concerned about the length of time that the reboot might take and the reduced capability they would have until it was completed.

Cause 1d: FE operators did not have an effective alternative to easily visualize the overall conditions of the system once the alarm processor failed. An alternative means of readily visualizing overall system conditions, including the status of critical facilities, would have enabled FE operators to become aware of forced line outages in a timely manner even though the alarms were non-functional. Typically, a dynamic map board or other type of display could provide a system status overview for quick and easy recognition by the operators. As with the prior causes, this deficiency precluded FE operators from detecting the degrading system conditions, taking corrective actions, and alerting MISO and neighboring systems.

D. The MISO State Estimator Is Ineffective from 12:15 to 16:04 EDT

It is common for reliability coordinators and control areas to use a state estimator to monitor the power system to improve the accuracy over raw telemetered data. The raw data are processed mathematically to make a “best fit” power flow model, which can then be used in other software applications, such as real-time contingency analysis, to simulate various conditions and outages to evaluate the reliability of the power system. Real-time contingency analysis is used to alert operators if the system is operating insecurely; it can be run either on a regular schedule (e.g., every five minutes), when triggered by some system event (e.g., the loss of a power plant or transmission line), or when initiated by an operator. MISO usually runs its state estimator every five minutes and contingency analysis less frequently. If the model does not have accurate and timely information about key facilities, then the state estimator may be unable to reach a solution or it will reach a solution that is labeled as having a high degree of error. On August 14, MISO’s state estimator and real-time contingency analysis tools were still under development and not fully mature. At about 12:15, MISO’s state estimator produced a solution with a large mismatch outside the acceptable tolerance. This was traced to the outage at 12:12:47 of Cinergy’s Bloomington-Denois Creek 230-kV line. This line tripped out due to a sleeve failure. Although this line was out of service, its status was not updated in the state estimator.

Line status information within MISO’s reliability coordination area is transmitted to MISO by the ECAR data network or direct links intended to be automatically linked to the state estimator. This requires coordinated data naming as well as instructions that link the data to the tools. For the Bloomington-Denois Creek line, the automatic linkage of line status to the state estimator had not yet been established. The line status was corrected manually and MISO’s analyst obtained a good

state estimator solution at about 13:00 and a real-time contingency analysis solution at 13:07. However, to troubleshoot this problem, he had turned off the automatic trigger that runs the state estimator every five minutes. After fixing the problem he forgot to re-enable the automatic trigger. So, although he had manually run the state estimator and real-time contingency analysis to reach a set of correct system analyses, the tools were not returned to normal automatic operation. Thinking the system had been successfully restored, the analyst went to lunch.

The fact that the state estimator was not running automatically on its regular five-minute schedule was discovered at about 14:40. The automatic trigger was re-enabled but again the state estimator failed to solve successfully. This time, the investigation identified the Stuart-Atlanta 345-kV line outage at 14:02 to be the likely cause. This line, jointly owned by DP&L and AEP, is monitored by DP&L. The line is under PJM's reliability umbrella rather than MISO's. Even though it affects electrical flows within MISO and could stall MISO's state estimator, the line's status had not been automatically linked to MISO's state estimator.

Cause 3a: MISO was using non-real-time information to monitor real-time operations in its area of responsibility. MISO was using its Flowgate Monitoring Tool (FMT) as an alternative method of observing the real-time status of critical facilities within its area of responsibility. However, the FMT was receiving information on facility outages from the NERC SDX, which is not intended as a real-time information system and is not required to be updated in real-time. Therefore, without real-time outage information, the MISO FMT was unable to accurately estimate real-time conditions within the MISO area of responsibility. If the FMT had received accurate line outage distribution factors representing current system topology, it would have identified a contingency overload on the Star-Juniper 345-kV line for the loss of the Hanna-Juniper 345-kV line as early as 15:10. This information would have enabled MISO to alert FE operators regarding the contingency violation and would have allowed corrective actions by FE and MISO. The reliance on non-real-time facility status information from the NERC SDX is not limited to MISO; others in the Eastern Interconnection use the same SDX information to calculate TLR curtailments in the IDC and make operational decisions on that basis. What was unique compared to other reliability coordinators on that day was MISO's reliance on the SDX for what they intended to be a real-time system monitoring tool.

The discrepancy between actual measured system flows (with Stuart-Atlanta out of service) and the MISO model (which assumed Stuart-Atlanta was in service) was still preventing the state estimator from solving correctly at 15:09 when, informed by the system engineer that the Stuart-Atlanta line appeared to be the problem, the MISO operator said (mistakenly) that this line was in service. The system engineer then tried unsuccessfully to reach a solution with the Stuart-Atlanta line modeled as in service until approximately 15:29, when the MISO reliability coordinator called PJM to verify the correct status. After the reliability coordinators determined that Stuart-Atlanta had tripped, MISO updated the state estimator and it solved correctly. The real-time contingency analysis was then run manually and solved successfully at 15:41. MISO's state estimator and contingency analysis were back under full automatic operation and solving effectively by 16:04, about two minutes before the trip of the Sammis-Star line and initiation of the cascade.

In summary, the MISO state estimator and real-time contingency analysis tools were effectively out of service between 12:15 and 15:41 and were not in full automatic operation until 16:04. This prevented MISO from promptly performing pre-contingency "early warning" assessments of power system reliability during the afternoon of August 14. MISO's ineffective diagnostic support contributed to FE's lack of situational awareness.

E. Precipitating Events: 345-kV Transmission Line Trips: 15:05 to 15:41 EDT

1. Summary

From 15:05:41 to 15:41:35, three 345-kV lines failed with power flows at or below each transmission line's emergency rating. Each trip and lockout was the result of a contact between an energized line and a tree that had grown so tall that it had encroached into the minimum safe clearance for the line. As each line failed, power flow was shifted onto the remaining lines. As each of the transmission lines failed and power flows shifted to other transmission paths, voltages on the rest of FE system degraded further. The following key events occurred during this period:

- 15:05:41: The Chamberlin-Harding 345-kV line tripped, reclosed, tripped again, and locked out.
- 15:31–33: MISO called PJM to determine if PJM had seen the Stuart-Atlanta 345-kV line outage. PJM confirmed Stuart-Atlanta was out.
- 15:32:03: The Hanna-Juniper 345-kV line tripped, reclosed, tripped again, and locked out.
- 15:35: AEP asked PJM to begin work on a 350 MW TLR to relieve overloading on the Star-South Canton line, not knowing the Hanna-Juniper 345-kV line had already tripped at 15:32.
- 15:36: MISO called FE regarding a post-contingency overload on the Star-Juniper 345-kV line for the contingency loss of the Hanna-Juniper 345-kV line, unaware at the start of the call that Hanna-Juniper had already tripped. MISO used the FMT to arrive at this assessment.
- 15:41:33–35: The Star-South Canton 345-kV line tripped, reclosed, tripped again at 15:41, and remained out of service, while AEP and PJM were discussing TLR relief options to reduce loading on the line.

2. Chamberlin-Harding 345-kV Line Trip at 15:05 EDT

Figure III.3 shows the location of the Chamberlin-Harding line and the two subsequent critical line trips.



Juniper ground fault current build up (fault current)

Line Trips

Time = 14.028 mSec

Faulted phase current

Harding-Chamberlin 345-kV fault at 15:05 EDT
DFR recorder taken from Harding-Juniper at Juniper

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Going to the fault location as determined from the relay data, the field team found the remains of trees and brush. At this location, conductor height measured 46 feet 7 inches, while the height of the felled tree measured 42 feet; however, portions of the tree had been removed from the site. This means that while it is difficult to determine the exact height of the line contact, the measured height is a minimum and the actual contact was likely three to four feet higher than estimated here. Burn marks were observed 35 feet 8 inches up the tree, and the crown of this tree was at least six feet taller than the observed burn marks. The tree showed evidence of fault current damage.

To be sure that the evidence of tree-to-line contacts and tree remains found at each site were linked to the events of August 14, the team looked at whether these lines had any prior history of outages in preceding months or years that might have resulted in the burn marks, debarking, and other evidence of line-tree contacts. Records establish that there were no prior sustained outages known to be caused by trees for these lines in 2001, 2002, or 2003. Chamberlin-Harding had zero outages for those years. Hanna-Juniper had six outages in 2001, ranging from four minutes to a maximum of 34 minutes — two were from an unknown cause, one was caused by lightning, and three were caused by a relay failure or mis-operation. Star-South Canton had no outages in that same two-and-a-half year period.

Like most transmission owners, FE patrols its lines regularly, flying over each transmission line twice a year to check on the condition of the rights-of-way. Notes from flyovers in 2001 and 2002 indicate that the examiners saw a significant number of trees and brush that needed clearing or trimming along many FE transmission lines.

FE operators were not aware that the system was operating outside first contingency limits after the Chamberlin-Harding trip (for the possible loss of Hanna-Juniper), because they did not conduct a contingency analysis. The investigation team has not determined whether the system status information used by the FE state estimator and contingency analysis model was being accurately updated.

Chamberlin-Harding was not one of the flowgates that MISO monitored as a key transmission location, so the reliability coordinator was unaware when FE's first 345-kV line failed. Although MISO received SCADA input of the line's status change, this was presented to MISO operators

Cause 2: FE did not effectively manage vegetation in its transmission line rights-of-way. The lack of situational awareness resulting from Causes 1a–1e would have allowed a number of system failure modes to go undetected. However, it was the fact that FE allowed trees growing in its 345-kV transmission rights-of-way to encroach within the minimum safe clearances from energized conductors that caused the Chamberlin-Harding, Hanna-Juniper, and Star-South Canton 345-kV line outages. These three tree-related outages triggered the localized cascade of the Cleveland-Akron 138-kV system and the over-loading and tripping of the Sammis-Star line, eventually snowballing into an uncontrolled wide-area cascade. These three lines experienced non-random, common mode failures due to unchecked tree growth. With properly cleared rights-of-way and calm weather, such as existed in Ohio on August 14, the chances of those three lines randomly tripping within 30 minutes is extremely small. Effective vegetation management practices would have avoided this particular sequence of line outages that triggered the blackout. However, effective vegetation management might not have precluded other latent failure modes. For example, investigators determined that there was an elevated risk of a voltage collapse in the Cleveland-Akron area on August 14 if the Perry 1 nuclear plant had tripped that afternoon in addition to Eastlake 5, because the transmission system in the Cleveland-Akron area was being operated with low bus voltages and insufficient reactive power margins to remain stable following the loss of Perry 1.

as breaker status changes rather than a line failure. Because their EMS system topology processor had not yet been linked to recognize line failures, it did not connect the breaker information to the loss of a transmission line. Thus, MISO's operators did not recognize the Chamberlin-Harding trip as a significant event and could not advise FE regarding the event or its consequences.

Further, without its state estimator and associated real-time contingency analysis, MISO was unable to identify potential overloads that would occur due to various line or equipment outages. Accordingly, when the Chamberlin-Harding 345-kV line tripped at 15:05, the state estimator did not produce results and could not predict an overload if the Hanna-Juniper 345-kV line were also to fail.

MISO did not discover that Chamberlin-Harding had tripped until after the blackout, when MISO reviewed the breaker operation log that evening. FE indicates that it discovered the line was out while investigating system conditions in response to MISO's call at 15:36, when MISO told FE that MISO's flowgate monitoring tool showed a Star-Juniper line overload following a contingency loss of Hanna-Juniper. However, investigators found no evidence within the control room logs or transcripts to show that FE knew of the Chamberlin-Harding line failure until after the blackout.

Cause 1e: FE did not have an effective contingency analysis capability cycling periodically on-line and did not have a practice of running contingency analysis manually as an effective alternative for identifying contingency limit violations.

Real-time contingency analysis, cycling automatically every 5–15 minutes, would have alerted the FE operators to degraded system conditions following the loss of the Eastlake 5 generating unit and the Chamberlin-Harding 345-kV line.

Initiating a manual contingency analysis after the trip of the Chamberlin-Harding line could also have identified the degraded system conditions for the FE operators. Knowledge of a contingency limit violation after the loss of Chamberlin-Harding and knowledge that conditions continued to worsen with the subsequent line losses would have allowed the FE operators to take corrective actions and notify MISO and neighboring systems of the developing system emergency. FE was operating after the trip of the Chamberlin-Harding 345-kV line at 15:05, such that the loss of the Perry 1 nuclear unit would have caused one or more lines to exceed their emergency ratings.

When the Chamberlin-Harding line locked out, the loss of this path caused the remaining three 345-kV paths into Cleveland from the south to pick up more load, with Hanna-Juniper picking up the most. The Chamberlin-Harding outage also caused more power to flow through the underlying 138-kV system.

3. FE Hanna-Juniper 345-kV Line Trips at 15:32 EDT

Incremental line current and temperature increases, escalated by the loss of Chamberlin-Harding, caused enough sag on the Hanna-Juniper line that it experienced a fault current due to tree contact, tripped and locked out at 15:32:03, with current flow at 2,050 amperes or 87.5 percent of its normal and emergency line rating of 2,344 amperes. Figure III.5 shows the Juniper digital fault recorder indicating the tree signature of a high-impedance ground fault. Analysis showed high arc resistance limiting the actual fault current well below the calculated fault current assuming a "bolted" (no arc resistance) fault.

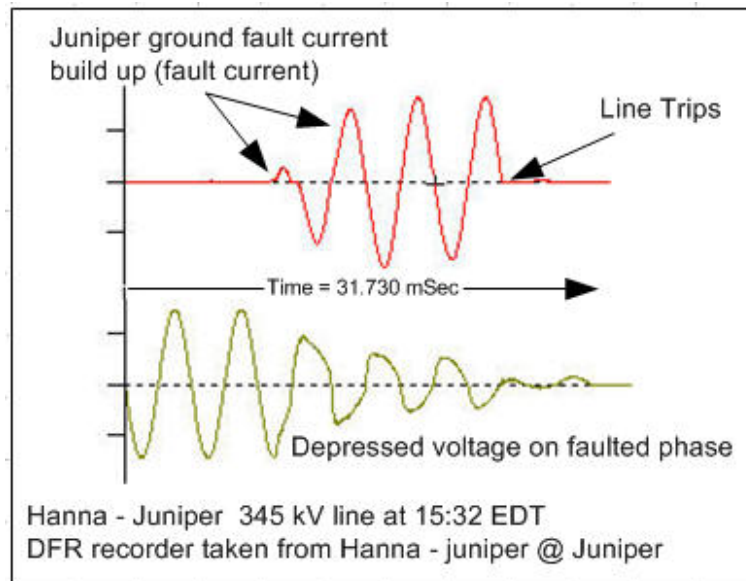


Figure III.5 — Juniper DFR Indication of Tree Contact for Loss of Hanna-Juniper

The tree contact occurred on the south phase of the Hanna-Juniper line, which is lower than the center phase due to construction design. Although little evidence remained of the tree during the field visit in October, the team observed a tree stump 14 inches in diameter at its ground line and talked to a member of the FE tree-trimming crew who witnessed the contact on August 14 and reported it to the FE operators. FE was conducting right-of-way vegetation maintenance and the tree crew at Hanna-Juniper was three spans away clearing vegetation near the line, when the contact occurred on August 14. FE provided photographs that clearly indicate that the tree was of excessive height. Similar trees nearby but not in the right-of-way were 18 inches in diameter at ground line and 60 feet in height. Further inspection showed at least 20 trees growing in this right-of-way.

When the Hanna-Juniper line tripped at 15:32:03, the Harding-Juniper 345-kV line tripped concurrently. Investigators believe the Harding-Juniper operation was an overtrip caused by a damaged coaxial cable that prevented the transmission of a blocking signal from the Juniper end of the line. Then the Harding-Juniper line automatically initiated a high-speed reclosure of both ring bus breakers at Juniper and one ring bus breaker at Harding. The A-Phase pole on the Harding breaker failed to reclose. This caused unbalanced current to flow in the system until the second Harding breaker reclosed automatically 7.5 seconds later.

Hanna-Juniper was loaded at 87.5 percent of its normal and emergency rating when it tripped. With this line open, almost 1,200 MVA had to find a new path to reach the loads in Cleveland. Loading on the remaining two 345-kV lines increased, with Star-Juniper taking the most of the power shift. This caused the loading on Star-South Canton to rise above normal but within its emergency rating, and pushed more power onto the 138-kV system. Flows west into Michigan decreased slightly and voltages declined somewhat in the Cleveland area.

Because its alarm system was not working, FE was not aware of the Chamberlin-Harding or Hanna-Juniper line trips. However, once MISO manually updated the state estimator model for the Stuart-Atlanta line outage, the software successfully completed a state estimation and contingency analysis at 15:41. But this left a 36-minute period, from 15:05 to 15:41, during which MISO did not anticipate the potential consequences of the Hanna-Juniper loss, and FE

operators knew of neither the line's loss nor its consequences. PJM and AEP recognized the overload on Star-South Canton, but had not expected it because their earlier contingency analysis did not examine enough lines within the FE system to foresee this result of the Hanna-Juniper contingency on top of the Chamberlin-Harding outage.

According to interviews, AEP had a contingency analysis capability that covered lines into Star. The AEP operator identified a problem for Star-South Canton overloads for a Sammis-Star line loss at about 15:33 and, at 15:35, asked PJM to begin developing a 350 MW TLR to mitigate it. The TLR was to relieve the actual overload above the normal rating then occurring on Star-South Canton, and to prevent an overload above the emergency rating on that line for the loss of Sammis-Star. But when they began working on the TLR, neither AEP nor PJM realized that Hanna-Juniper had already tripped at 15:32, further degrading system conditions. Most TLRs are for cuts of 25 to 50 MW. A 350 MW TLR request was highly unusual and the operators were attempting to confirm why so much relief was suddenly required before implementing the requested TLR.

Cause 3b: MISO did not have real-time topology information for critical lines mapped into its state estimator. The MISO state estimator and network analysis tools were still considered to be in development on August 14 and were not fully capable of automatically recognizing changes in the configuration of the modeled system. Following the trip of lines in the Cinergy system at 12:12 and the DP&L Stuart-Atlanta line at 14:02, the MISO state estimator failed to solve correctly as a result of large numerical mismatches. MISO real-time contingency analysis, which operates only if the state estimator solves, did not operate properly in automatic mode again until after the blackout. Without real-time contingency analysis information, the MISO operators did not detect that the FE system was in a contingency violation after the Chamberlin-Harding 345-kV line tripped at 15:05. Since MISO was not aware of the contingency violation, MISO did not inform FE and thus FE's lack of situational awareness described in Causes 1a-e was allowed to continue. With an operational state estimator and real-time contingency analysis, MISO operators would have known of the contingency violation and could have informed FE, thus enabling FE and MISO to take timely actions to return the system to within limits.

Less than ten minutes elapsed between the loss of Hanna-Juniper, the overload above the normal limits of Star-South Canton, and the Star-South Canton trip and lock-out. This shortened time span between the Hanna-Juniper and Star-South Canton line trips is a first hint that the pace of events was beginning to accelerate. This activity between AEP and PJM was the second time on August 14 an attempt was made to remove actual and contingency overloads using an administrative congestion management procedure (reallocation of transmission through TLR) rather than directly ordering generator shifts to relieve system overloads first. The prior incident was the TLR activity between Cinergy and MISO for overloads on the Cinergy system.

The primary means MISO was using to assess reliability on key flowgates was its flowgate monitoring tool. After the Chamberlin-Harding 345-kV line outage at 15:05, the FMT produced incorrect results because the outage was not reflected in the model. As a result, the tool assumed that Chamberlin-Harding was still available and did not predict an overload for the loss of the Hanna-Juniper 345-kV line.

When Hanna-Juniper tripped at 15:32, the resulting overload was detected by MISO SCADA and set off alarms to MISO's system operators, who then phoned FE about it. Because both MISO's state estimator was still in a developmental state, was not working properly, and the flowgate monitoring tool did not have updated line status information, MISO's ability to recognize evolving contingency situations on the FE system was impaired.

Although an inaccuracy was identified with MISO's flowgate monitoring tool, it still functioned with reasonable accuracy and prompted MISO to call FE to discuss the Hanna-Juniper line problem. The FMT showed an overload at 108 percent of the operating limit. However, the tool did not recognize that Chamberlin-Harding was out of service at the time. If the distribution factors had been updated, the overload would have appeared to be even greater. It would not have identified problems south of Star since that was not part of the flowgate and thus was not modeled in MISO's flowgate monitor.

4. Loss of the Star-South Canton 345-kV Line at 15:41 EDT

The Star-South Canton line crosses the boundary between FE and AEP; each company owns the portion of the line within its service territory and manages the right-of-way for that portion. The Star-South Canton line tripped and reclosed three times on the afternoon of August 14, first at 14:27:15 while operating at less than 55 percent of its rating. With the loss of Chamberlin-Harding and Hanna-Juniper, there was a substantial increase in load on the Star-South Canton line. This line, which had relayed and reclosed earlier in the afternoon at 14:27, again relayed and reclosed at 15:38:47. It later relayed and locked out in a two-second sequence from 15:41:33 to 15:41:35 on a Phase C ground fault. Subsequent investigation found substantial evidence of tree contact. It should be noted that this fault did not have the typical signature of a high impedance ground fault.

Following the first trip of the Star-South Canton line at 14:27, AEP called FE at 14:32 to discuss the trip and reclose of the line. AEP was aware of breaker operations at their end (South Canton) and asked about operations at FE's Star end. FE indicated they had seen nothing at their end of the line but AEP reiterated that the trip occurred at 14:27 and that the South Canton breakers had reclosed successfully.

There was an internal FE conversation about the AEP call at 14:51 expressing concern that they had not seen any indication of an operation; but, lacking evidence within their control room, the FE operators did not pursue the issue. According to the transcripts, FE operators dismissed the information as either not accurate or not relevant to their system, without following up on the discrepancy between the AEP event and the information observed in the FE control room. There was no subsequent verification of conditions with MISO. Missing the trip and reclose of the Star-South Canton at 14:27, despite a call from AEP inquiring about it, was a clear indication that the FE operators' loss of situational awareness had begun.

At 15:19, AEP called FE back to confirm that the Star-South Canton trip had occurred and that an AEP technician had confirmed the relay operation at South Canton. The FE operator restated that because they had received no trouble alarms, they saw no problem. At 15:20, AEP decided to treat the South Canton digital fault recorder and relay target information as a spurious relay operation and to check the carrier relays to determine what the problem might be.

A second trip and reclose of Star-South Canton occurred at 15:38:48. Finally, at 15:41:35, the line tripped and locked out at the Star substation. A short-circuit-to-ground occurred in each case. Less than ten minutes after the Hanna-Juniper line trip at 15:32, Star-South Canton tripped with power flow at 93.2 percent of its emergency rating. AEP had called FE three times between the initial trip at 14:27 and 15:45 to determine if FE knew the cause of the line trips.

Investigators inspected the right-of-way at the location indicated by the relay digital fault recorders, which was in the FE portion of the line. They found debris from trees and vegetation that had been felled. At this location, the conductor height was 44 feet 9 inches. The identifiable

tree remains measured 30 feet in height, although the team could not verify the location of the stump, nor find all sections of the tree. A nearby cluster of trees showed significant fault damage, including charred limbs and de-barking from fault current. Topsoil in the area of the tree trunk was also disturbed, discolored and broken up, a common indication of a higher magnitude fault or multiple faults. Analysis of another stump showed that a fourteen year-old tree had recently been removed from the middle of the right-of-way.

It was only after AEP notified FE that the Star-South Canton 345-kV circuit had tripped and locked out at 15:42 did the FE control area operator compare this information to the breaker statuses for their end of the line at Star. After 15:42, the FE operator failed to immediately inform the MISO and adjacent control areas when they became aware that system conditions had changed due to unscheduled equipment outages that might affect other control areas.

After the Star-South Canton line was lost, flows increased greatly on the 138-kV system toward Cleveland, and the Akron area voltage levels began to degrade on the 138-kV and 69-kV system. At the same time, power flow was increasing on the Sammis-Star line due to the 138-kV line trips and the dwindling number of remaining transmission paths into Cleveland from the south.

5. Degrading System Conditions After the 345-kV Line Trips

Figure III.6 shows the line loadings calculated by the investigation team as the 345-kV lines in northeast Ohio began to trip. Showing line loadings on the 345-kV lines as a percent of normal rating, the graph tracks how the loading on each line increased as each subsequent 345-kV and 138-kV line tripped out of service between 15:05 (Chamberlin-Harding) and 16:06 (Dale-West Canton). As the graph shows, none of the 345- or 138-kV lines exceeded their normal ratings on an actual basis (although contingency overloads existed) until after the combined trips of Chamberlin-Harding and Hanna-Juniper. But immediately after Hanna-Juniper was lost, Star-South Canton's loading jumped from an estimated 82 percent of normal to 120 percent of normal (still below its emergency rating) and remained at that level for ten minutes before tripping out. To the right, the graph shows the effects of the 138-kV line failures (discussed next) on the remaining 345-kV line, i.e., Sammis-Star's loading increased steadily above 100 percent with each succeeding 138-kV line lost.

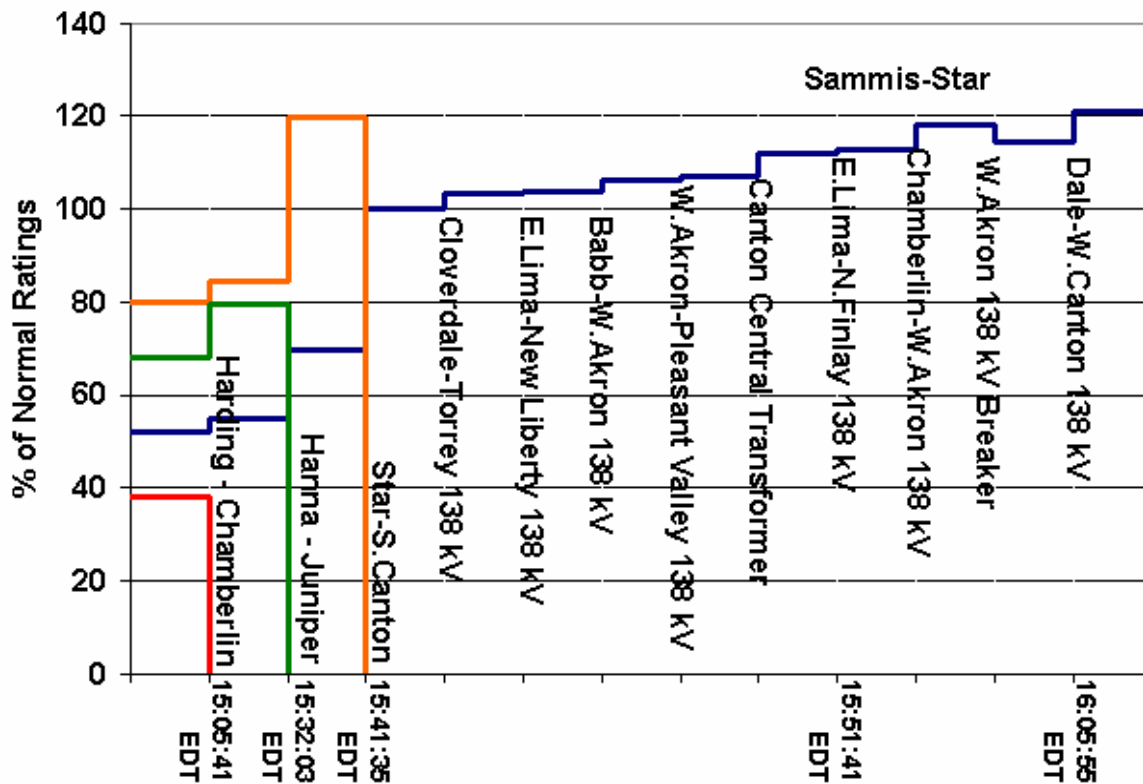


Figure III.6 — Line Loadings as the Northeast Ohio 345-kV Lines Trip

Following the loss of the Chamberlin-Harding 345-kV line, contingency limit violations existed for:

- The Star-Juniper 345-kV line, whose loading would exceed its emergency limit for the loss of the Hanna-Juniper 345-kV line; and
- The Hanna-Juniper and Harding-Juniper 345-kV lines, whose loadings would exceed emergency limits for the loss of the 1,255 MW Perry Nuclear Generating Plant.

Operationally, once the FE system entered an n-1 contingency violation state at 15:05 after the loss of Chamberlin-Harding, any facility loss beyond that pushed them into a more unreliable state. To restore the system to a reliable operating state, FE needed to reduce loading on the Star-Juniper, Hanna-Juniper, and Harding-Juniper lines (normally within 30 minutes) such that no single contingency would violate an emergency limit on one of those lines. Due to the non-random nature of events that afternoon (overgrown trees contacting lines), not even a 30-minute response time was adequate as events were beginning to speed up. The Hanna-Juniper line tripped and locked out at 15:32, only 27 minutes after Chamberlin-Harding.

6. Phone Calls Indicated Worsening Conditions

During the afternoon of August 14, FE operators talked to their field personnel, MISO, PJM, adjoining systems (such as AEP), and customers. The FE operators received pertinent information from all of these sources, but did not grasp some key information about the condition of the system from the clues offered. This information included a call from the FE eastern control

center asking about possible line trips, a call from the Perry nuclear plant regarding what looked like near-line trips, AEP calling about their end of the Star-South Canton line tripping, and MISO and PJM calling about possible line overloads.

At 15:35, the FE control center received a call from the Mansfield 2 plant operator, concerned about generator fault recorder triggers and excitation voltage spikes with an alarm for over-excitation; a dispatcher called reporting a “bump” on their system. Soon after this call, the FE Reading, Pennsylvania, control center called reporting that fault recorders in the Erie west and south areas had activated, and wondering if something had happened in the Ashtabula-Perry area. The Perry nuclear plant operator called to report a “spike” on the unit’s main transformer. When he went to look at the metering it was “still bouncing around pretty good. I’ve got it relay tripped up here ... so I know something ain’t right.”

It was at about this time that the FE operators began to suspect something might be wrong, but did not recognize that the problems were on their own system. “It’s got to be in distribution, or something like that, or somebody else’s problem ... but I’m not showing anything.” Unlike many transmission system control centers, the FE center did not have a map board, which might have shown the location of significant line and facility outages within the control area.

At 15:36, MISO contacted FE regarding the post-contingency overload on Star-Juniper for the loss of the Hanna-Juniper 345-kV line. Unknown to MISO and FE, Hanna-Juniper had already tripped four minutes earlier.

At 15:42, the FE western transmission operator informed the FE computer support staff that the EMS system functionality was compromised. “Nothing seems to be updating on the computers.... We’ve had people calling and reporting trips and nothing seems to be updating in the event summary... I think we’ve got something seriously sick.” This is the first evidence that a member of the FE control room operating staff recognized that their EMS system was degraded. There is no indication that he informed any of the other operators at this time. However, the FE computer support staff discussed the subsequent EMS corrective action with some control room operators shortly thereafter.

Also at 15:42, the Perry plant operator called back with more evidence of problems. “I’m still getting a lot of voltage spikes and swings on the generator.... I don’t know how much longer we’re going to survive.”

At 15:45, the tree trimming crew reported that they had witnessed a tree-caused fault on the Eastlake-Juniper line. However, the actual fault was on the Hanna-Juniper line in the same vicinity. This information added to the confusion in the FE control room because the operator had indication of flow on the Eastlake-Juniper line.

After the Star-South Canton line tripped a third time and locked out at 15:42, AEP called FE at 15:45 to discuss and inform them that they had additional lines showing overloads. FE recognized then that the Star breakers had tripped and remained open.

At 15:46, the Perry plant operator called the FE control room a third time to say that the unit was close to tripping off: “It’s not looking good.... We ain’t going to be here much longer and you’re going to have a bigger problem.”

At 15:48, an FE transmission operator sent staff to man the Star substation, and then at 15:50, requested staffing at the regions, beginning with Beaver, then East Springfield. This act, 43

minutes after the Chamberlin-Harding line trip and 18 minutes before the Sammis-Star trip, signaled the start of the cascade, and was the first clear indication that at least one of the FE system operating staff was beginning to recognize that an emergency situation existed.

At the same time the activities above were unfolding at FE, AEP operators grew quite concerned about the events unfolding on their ties with FE. Beginning with the first trip of the Star-South Canton 345 kV line, AEP contacted FE attempting to verify the trip. Later, their state estimation and contingency analysis tools indicated a contingency overload for Star-South Canton 345 kV line and AEP requested Transmission Loading Relief action by their reliability coordinator, PJM. A conversation beginning at 15:35 between AEP and PJM showed considerable confusion on the part of the reliability coordinator.

PJM Operator: "Where specifically are you interested in?"

AEP Operator: "The South Canton-Star."

PJM Operator: "The South Canton-Star. Oh, you know what? This is interesting. I believe this one is ours...that one was actually in limbo one night, one time we needed it."

AEP Operator: "For AEP?"

PJM Operator: "For AEP, yes. I'm thinking. South Canton - where'd it go? South Canton-Star, there it is. South Canton-Star for loss of Sammis-Star?"

AEP Operator: "Yeah."

PJM Operator: "That's the one. That's currently ours. You need it?"

AEP Operator: "I believe. Look what they went to."

PJM Operator: "Let's see. Oh, man. Sammis-Star, okay. Sammis-Star for South Canton-Star. South Canton-Star for Sammis-Star, (inaudible). All right, you're going to have to help me out. What do you need on it...?"

AEP Operator: "Pardon?"

PJM Operator: "What do you need? What do you need on it? How much relief you need?"

AEP Operator: "Quite a bit."

PJM Operator: "Quite a bit. What's our limit?"

AEP Operator: "I want a 3-B."

PJM Operator: "3-B."

Cause 3c: The PJM and MISO reliability coordinators lacked an effective procedure on when and how to coordinate an operating limit violation observed by one of them in the other's area due to a contingency near their common boundary. The lack of such a procedure caused ineffective communications between PJM and MISO regarding PJM's awareness of a possible overload on the Sammis-Star line as early as 15:48. An effective procedure would have enabled PJM to more clearly communicate the information it had regarding limit violations on the FE system, and would have enabled MISO to be aware of those conditions and initiate corrective actions with FE.

AEP Operator: "It's good for 1,412, so I need how much cut off?"

PJM Operator: "You need like... 230, 240."

PJM Operator: "Now let me ask you, there is a 345 line locked out DPL Stuart to Atlanta. Now, I still haven't had a chance to get up and go see where that is. Now, I don't know if that would have an effect."

AEP Operator: "1,341. I need - man, I need 300. I need 300 megawatts cut."

PJM Operator: "Okay. Verify our real-time flows on..."

From this conversation it appears that the PJM reliability coordinator is not closely monitoring Dayton Power and Light and AEP facilities (areas for which PJM has reliability coordinator responsibility) in real time. Further, the operator must leave the desk to determine where a 345 kV line is within the system, indicating a lack of familiarity with the system.

AEP Operator: "What do you have on the Sammis-Star, do you know?"

PJM Operator: "I'm sorry? Sammis-Star, okay, I'm showing 960 on it and it's highlighted in blue. Tell me what that means on your machine."

AEP Operator: "Blue? Normal. Well, it's going to be in blue, I mean - that's what's on it?"

PJM Operator: "960, that's what it says."

AEP Operator: "That circuit just tripped. South Canton-Star."

PJM Operator: "Did it?"

AEP Operator: "It tripped and re-closed..."

AEP Operator: "We need to get down there now so they can cut the top of the hour. Is there anything on it? What's the flowgate, do you know?"

PJM Operator: "Yeah, I got it in front of me. It is-it is 2935."

AEP Operator: "Yeah...2935. I need 350 cut on that."

PJM Operator: "Whew, man."

AEP Operator: "Well, I don't know why. It popped up all of a sudden like that...that thing just popped up so fast."

PJM Operator: "And... 1,196 on South Canton. Can you verify these? And 960 on - South Canton-Star 1,196, Sammis-Star 960?"

AEP Operator: "They might be right, I'm..."

PJM Operator: "They were highlighted in blue, I guess I thought maybe that was supposed to be telling me something."

This conversation demonstrates that the PJM operator is not fully familiar with the monitoring system being used. The operator is questioning the AEP operator about what something in blue on the screen represents since presumably the AEP operator is more familiar with the system the PJM operator is using.

The AEP operators are witnessing portions of the 138 kV cascade and relaying that information to the PJM operator. The PJM operator, as seen below, is looking at a state estimator screen and not real time flows or status of the AEP system and hence is unaware of these line trips from his monitoring system.

PJM Operator: "...Sammis-Star, I'm still seeing flow on both those lines. Am I'm looking at state estimated data?"

AEP Operator: "Probably."

PJM Operator: "Yeah, it's behind, okay. You're able to see raw data?"

AEP Operator: "Yeah; it's open. South Canton-Star is open."

PJM Operator: "South Canton-Star is open. Torrey-Cloverdale?"

AEP Operator: "Oh, my God, look at all these open..."

AEP: "We have more trouble... more things are tripping. East Lima and New Liberty tripped out. Look at that."

AEP: "Oh, my gosh, I'm in deep..."

PJM Operator: "You and me both, brother. What are we going to do? You need something, you just let me know."

AEP Operator: "Now something else just opened up. A lot of things are happening."

PJM Operator: "Okay... South Canton-Star. Okay, I'm seeing a no-flow on that. So what are we overloading now? We lost South Canton-Star, we're going to overload Sammis-Star, right? The contingency is going to overload, which is the Sammis-Star. The FE line is going to overload as a result of that. So I should probably talk to MISO."

AEP Operator: "Pardon?"

PJM Operator: "I should probably talk to MISO because they're going to have to talk to FE."

As the AEP operators continue to witness the evolving cascade of the FE 138 kV system, the conversation ended at this point and PJM called MISO at 15:55. PJM reported the Star-South Canton trip to MISO, but their measures of the resulting line flows on the FE Sammis-Star line did not match, causing them to wonder whether the Star-South Canton line had returned to service. From the MISO operator phone transcripts:

PJM Operator: "...AEP, it looks like they lost South Canton-Star 345 line, and we are showing a contingency for that line and the Sammis-Star line, and one of them lost the other. Since they lost that line, I was wondering if you could verify flows on the Sammis-Star line for me at this time."

MISO Operator: "Well, let's see what I've got. I know that First Energy lost their Juniper line, too."

PJM Operator: "Did they?"

MISO Operator: "They are still investigating that, too. So the Star-Juniper line was overloaded."

PJM Operator: "Star-Juniper."

MISO Operator: "And they recently have got that under control here."

PJM Operator: "And when did that trip? That might have..."

MISO Operator: "I don't know yet. I still have - I have not had that chance to investigate it. There is too much going on right now."

PJM Operator: "Yeah, we are trying to figure out what made that one jump up on us so quick."

MISO Operator: "It may be a combination of both. You guys lost South Canton to Star."

PJM Operator: "Yes."

MISO Operator: "And we lost Hanna to Juniper it looks like."

PJM Operator: "Yes. And we were showing an overload for Sammis to Star for the South Canton to Star. So I was concerned, and right now I am seeing AEP systems saying Sammis to Star is at 1378."

MISO Operator: "All right. Let me see. I have got to try and find it here, if it is possible and I can go from here to Juniper Star. How about 1109?"

PJM Operator: "1,109?"

MISO Operator: "I see South Canton Star is open, but now we are getting data of 1199, and I am wondering if it just came after."

PJM Operator: "Maybe it did. It was in and out, and it had gone out and back in a couple of times."

MISO Operator: "Well, yeah, it would be no good losing things all over the place here."

PJM Operator: "All right. I just wanted to verify that with you, and I will let you tend to your stuff."

MISO Operator: "Okay."

PJM Operator: "Thank you, sir. Bye."

Considering the number of facilities lost, and that each reliability coordinator is discovering new lines are out that he did not previously know, there is an eerie lack of urgency or any discussion of actions to be taken. The MISO operator provided some additional information about

transmission line outages in FE, even though they did not have direct monitoring capabilities of their facilities on August 14. The PJM operator indicated that the South Canton-Star line was out of service, but did not relay any of the information regarding the other lines that were reported as tripping by the AEP operator. The MISO operator did not act on this information and PJM operator did not press the issue.

As shown by the investigation, by 15:55 at the start of this PJM-MISO call, the overload on Sammis-Star line exceeded 110% and continued to worsen. The overload began at 15:42 after the Star - S. Canton 345kV line locked open. At 16:05:57 just prior to tripping, fault recorders show a Sammis-Star flow of 2,850 amperes or 130% of its emergency 2193 ampere rating.

At 15:56, PJM was still concerned about the impact of the Star-South Canton trip, and PJM called FE to report that Star-South Canton had tripped and that PJM thought Sammis-Star was in actual emergency limit overload. FE could not confirm this overload. Investigators later discovered that FE was using a higher rating for the Sammis-Star line than was being used by MISO, AEP, and PJM — indicating ineffective coordination of FE line ratings with others.⁴ FE informed PJM that Hanna-Juniper was also out of service. At this time, FE operators still believed that the problems existed beyond their system, one of them saying, “AEP must have lost some major stuff.”

Modeling indicates that the return of either the Hanna-Juniper or Chamberlin-Harding lines would have diminished, but not alleviated, all of the 138-kV overloads. The return of both lines would have restored all of the 138 lines to within their emergency ratings. However, all three 345-kV lines had already been compromised due to tree contacts, so it is unlikely that FE would have successfully restored either line had they known it had tripped out. Also, since Star-South Canton had already tripped and reclosed three times, it is unlikely that an operator knowing this would have trusted it to operate securely under emergency conditions. While generation redispatch scenarios alone would not have solved the overload problem, modeling indicates that shedding load in the Cleveland and Akron areas could have reduced most line loadings to within emergency range and helped to stabilize the system. However, the amount of load shedding required grew rapidly as the FE system unraveled.

F. Localized Cascade of the 138-kV System in Northeastern Ohio: 15:39 to 16:08 EDT

1. Summary

At 15:39, a series of 138-kV line trips occurred in the vicinity of Akron because the loss of the Chamberlin-Harding, Hanna-Juniper, and Star-South Canton 345-kV lines overloaded the 138-kV system with electricity flowing north toward the Akron and Cleveland loads. Voltages in the Akron area also began to decrease and eventually fell below low limits.

One of the two Pleasant Valley-West Akron lines was the first 138-kV line to trip at 15:39:37, indicating the start of a cascade of 138-kV line outages in that area. A total of seven 138-kV

⁴ Specifically, FE was operating Sammis-Star assuming that the 345-kV line was rated for summer normal use at 1,310 MVA, with a summer emergency limit rating of 1,310 MVA. In contrast, MISO, PJM, and AEP were using a more conservative 950 MVA normal rating and 1,076 MVA emergency rating for this line. The facility owner (in this case FE) develops the line rating. It has not been determined when FE changed the ratings it was using; they did not communicate the changes to all concerned parties.

lines tripped during the next 20 minutes, followed at 15:59 by a stuck-breaker operation that cleared the 138-kV bus at West Akron and instantaneously opened five more 138-kV lines. Four additional 138-kV lines eventually opened over a three-minute period from 16:06 to 16:09, after the Sammis-Star 345-kV line opened to signal the transition from a localized failure to a spreading wide-area cascade.

During this same period at 15:45:41, the Canton Central-Tidd 345-kV line tripped and then reclosed at 15:46:29. The Canton Central 345/138-kV Circuit Breaker A1 operated multiple times, causing a low air pressure problem that inhibited circuit breaker tripping. This event forced the Canton Central 345/138-kV transformer to disconnect and remain out of service, further weakening the Canton-Akron area 138-kV transmission system.

Approximately 600 MW of customer loads were shut down in Akron and areas to the west and south of the city during the cascade because they were being served by transformers connected to those lines. As the lines failed, severe voltage drops caused a number of large industrial customers with voltage-sensitive equipment to go off-line automatically to protect their operations.

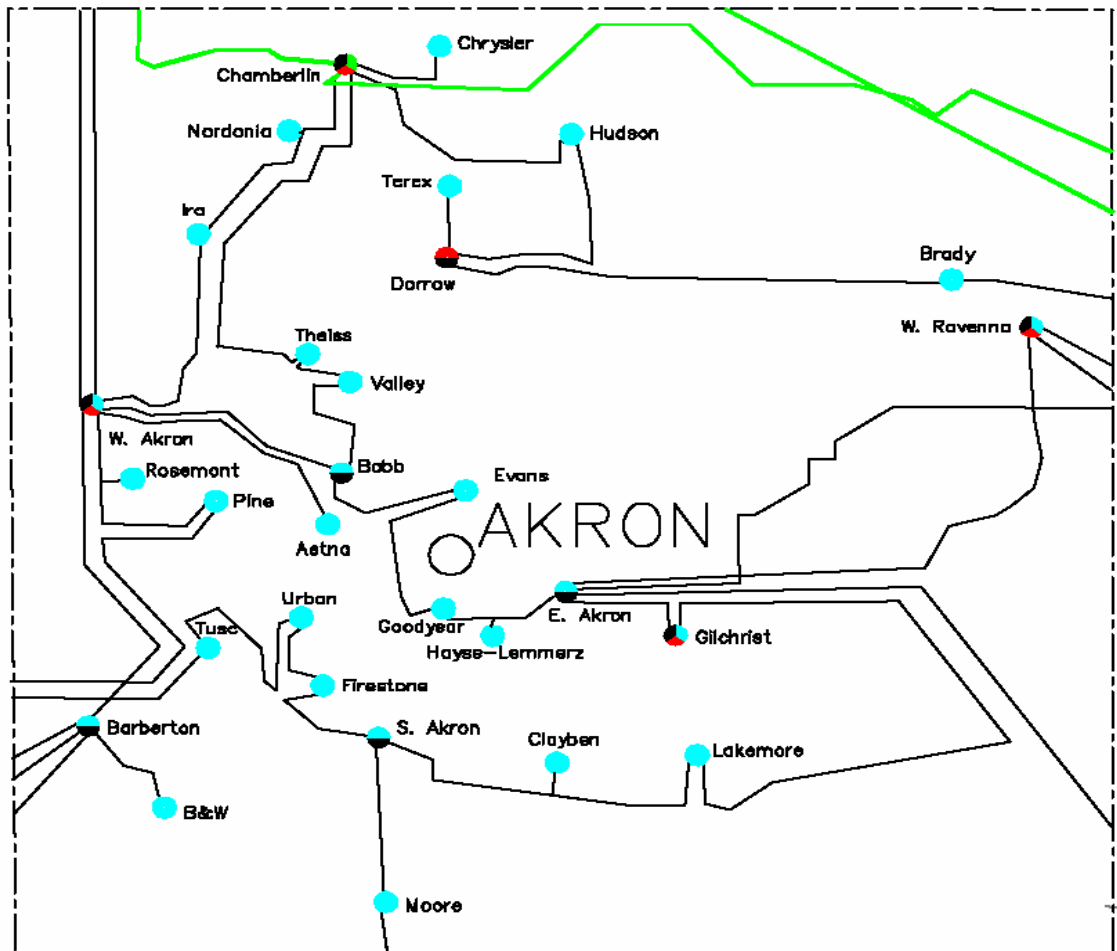


Figure III.7 — Akron Area Substations Participating in Localized 138-kV Cascade

2. 138-kV Localized Cascade Sequence of Events

From 15:39 to 15:58:47, seven 138-kV lines in northern Ohio tripped and locked out.

Table III.1 — 138-kV Line Trips Near Akron: 15:39 to 15:58:47

15:39:17	Pleasant Valley-West Akron 138-kV line tripped and reclosed at both ends.
15:42:05	Pleasant Valley-West Akron 138-kV West line tripped and reclosed.
15:44:40	Pleasant Valley-West Akron 138-kV West line tripped and locked out. B Phase had sagged into the underlying distribution conductors.
15:42:49	Canton Central-Cloverdale 138-kV line tripped and reclosed.
15:45:40	Canton Central-Cloverdale 138-kV line tripped and locked out. Phase-to-ground pilot relay targets were reported at both ends of the line. DFR analysis identified the fault to be 7.93 miles from Canton Central. The Canton Central 138-kV bus is a ring bus. A 138-kV circuit breaker failed to clear the 138-kV line fault at Canton Central. This breaker is common to the 138-kV autotransformer bus and the Canton Central-Cloverdale 138-kV line.
15:42:53	Cloverdale-Torrey 138-kV line tripped.
15:44:12	East Lima-New Liberty 138-kV line tripped. B Phase sagged into the underbuild.
15:44:32	Babb-West Akron 138-kV line tripped and locked out.
15:51:41	East Lima-North Findlay 138-kV line tripped and reclosed at the East Lima end only. At the same time, the Fostoria Central-North Findlay 138-kV line tripped and reclosed, but never locked out.
15:58:47	Chamberlin-West Akron 138-kV line tripped. Relays indicate a probable trip on overload.

With the Canton Central-Cloverdale 138-kV line trip at 15:45:40, the Canton Central 345-kV and 138-kV circuit breakers opened automatically to clear the fault via breaker failure relaying. Transfer trip initiated circuit breaker tripping at the Tidd substation end of the Canton Central-Tidd 345-kV line. A 345-kV disconnect opened automatically disconnecting two autotransformers from the Canton Central-Tidd 345-kV line after the fault was interrupted. The 138-kV circuit breaker's breaker-failure relay operated as designed to clear the fault. After the 345-kV disconnect opened and the 345-kV circuit breakers automatically reclosed, Canton Central-Tidd 345kV was restored at 15:46:29.

Table III.2 — West Akron Stuck Breaker Failure

15:59:00	West Akron-Aetna 138-kV line opened.
15:59:00	Barberton 138-kV line opened at West Akron end only. West Akron-B18 138-kV tie breaker opened, affecting West Akron 138/12-kV transformers #3, 4, and 5 fed from Barberton.
15:59:00	West Akron-Granger-Stoney-Brunswick-West Medina opened.
15:59:00	West Akron-Pleasant Valley 138-kV East line (Q-22) opened.
15:59:00	West Akron-Rosemont-Pine-Wadsworth 138-kV line opened.

The West Akron substation 138-kV bus was cleared at 15:59:00 due to a circuit breaker failure. The circuit breaker supplied a 138/69-kV transformer. The transformer phase directional power relay operated to initiate the trip of the breaker and its subsequent breaker failure backup

protection. There was no system fault at the time. The phase directional power relay operated because the 69-kV system in the Akron area became a supply to the 138-kV system. This reversal of power was due to the number of 138-kV lines that had tripped due to overloads and line faults caused by line overloads.

Investigators believe that the 138-kV circuit breaker failed because it was slow to operate. At 15:59:00, the West Akron 138-kV bus cleared from a failure to trip relay on the 138-kV circuit breaker B26, which supplies the 138/69-kV transformer number 1. The breaker trip was initiated by a phase directional overcurrent relay in the B26 relay circuit looking directionally into the 138-kV system from the 69-kV system. The West Akron 138/12-kV transformers remained connected to the Barberton-West Akron 138-kV line, but power flow to West Akron 138/69-kV transformer number 1 was interrupted. Output of the failure to trip (breaker failure) timer initiated a trip of all five remaining 138-kV lines connected at West Akron. Investigators believe that the relay may have operated due to high reactive power flow into the 138-kV system. This is possible even though power was flowing into the 69-kV system at the time.

From 16:00 to 16:08:59, four additional 138-kV lines tripped and locked out, some before and some after the Sammis-Star 345-kV line trip. After the Cloverdale-Torrey line failed at 15:42, Dale-West Canton was the most heavily loaded line on the FE system. It held on, although overloaded to between 160 and 180 percent of its normal rating, until tripping at 16:05:55. The loss of the Dale-West Canton 138-kV line had a significant effect on the area, and voltages dropped significantly after the loss of this line.

Even more importantly, loss of the Dale-West Canton line shifted power from the 138-kV system back to the remaining 345-kV network, pushing Sammis-Star's loading above 120 percent of its rating. This rating is a substation equipment rating rather than a transmission line thermal rating, therefore sag was not an issue. Two seconds later, at 16:05:57, Sammis-Star tripped and locked out. Unlike the previous three 345-kV lines, which tripped on short circuits due to tree contacts, Sammis-Star tripped because its protective relays saw low apparent impedance (depressed voltage divided by abnormally high line current), i.e., the relay reacted as if the high flow was due to a short circuit. Although three more 138-kV lines dropped quickly in Ohio following the Sammis-Star trip, loss of the Sammis-Star line marked the turning point at which problems in northeast Ohio initiated a cascading blackout across the Northeast.

Table III.3 — Additional 138-kV Line Trips Near Akron

16:05:55	Dale-West Canton 138- kV line tripped at both ends, reclosed at West Canton only.
16:05:57	Sammis-Star 345-kV line tripped.
16:06:02	Star-Urban 138-kV line tripped (reclosing is not initiated for backup trips).
16:06:09	Richland-Ridgeville-Napoleon-Stryker 138-kV line tripped and locked out at all terminals.
16:08:58	Ohio Central-Wooster 138-kV line tripped.
16:08:55	East Wooster-South Canton 138-kV line tripped, but successful automatic reclosing restored this line.

3. Sammis-Star 345-kV Line Trip: Pivot Point

Sammis-Star did not trip due to a short circuit to ground (as did the prior 345-kV lines that tripped). Sammis-Star tripped due to protective relay action that measured low apparent impedance (depressed voltage divided by abnormally high line current) (Figure III.10). There

was no fault and no major power swing at the time of the trip — rather, high flows above the line's emergency rating, together with depressed voltages, caused the overload to appear to the protective relays as a remote fault on the system. In effect, the relay could no longer differentiate between a remote three-phase fault and a high line-load condition. Moreover, the reactive flows (Var) on the line were almost ten times higher than they had been earlier in the day. The steady state loading on the line had increased gradually to the point where the operating point entered the zone 3 relay trip circle. The relay operated as it was designed to do. By design, reclosing is not initiated for trips initiated by backup relays.

As shown in Figure III.8, the Sammis-Star line trip completely severed the 345-kV path into northern Ohio from southeast Ohio, triggering a new, fast-paced sequence of 345-kV transmission line trips in which each line trip placed a greater flow burden on those lines remaining in service. After Sammis-Star tripped, there were only three paths left for power to flow into northern Ohio: (1) from northwestern Pennsylvania to northern Ohio around the south shore of Lake Erie, (2) from southern Ohio, and (3) from eastern Michigan and Ontario. Northeastern Ohio had been substantially weakened as a source of power to eastern Michigan, making the Detroit area more reliant on 345-kV lines west and northwest of Detroit, and from northwestern Ohio to eastern Michigan.

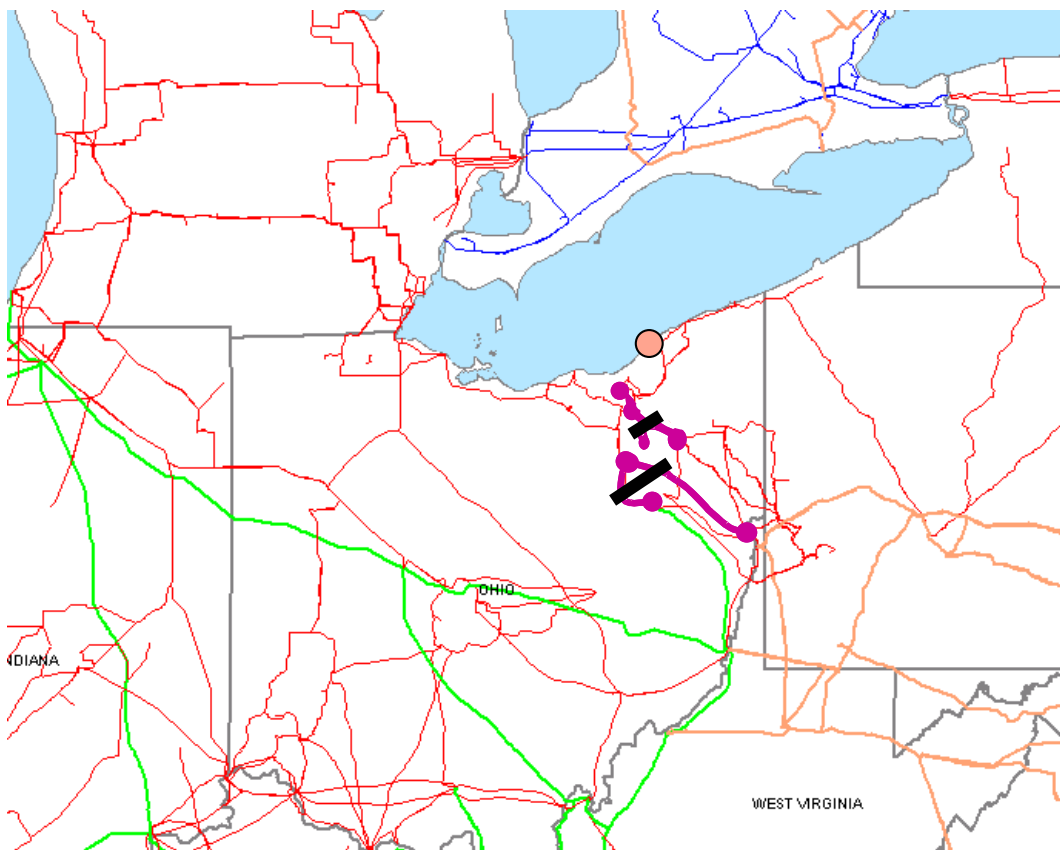


Figure III.8 — Cleveland-Akron Cut Off

After the Sammis-Star line trip, the conditions were set for an uncontrolled cascade of line failures that would separate the northeastern United States and eastern Canada from the rest of the Eastern Interconnection, then a breakup and collapse of much of that newly formed island. An important distinction is drawn here — that no events, actions, or failures to take action after

the Sammis-Star trip can be deemed to have caused the blackout. Later sections will address other factors that affected the extent and severity of the blackout.

The Sammis-Star line tripped at Sammis Generating Station due to a zone 3 impedance relay. There were no system faults occurring at the time. The relay tripped because increased real and reactive power flow caused the apparent impedance to be within the impedance circle (reach) of the relay. Several 138-kV line outages just prior to the tripping of Sammis-Star contributed to the tripping of this line. Low voltages and the increased reactive power flow into the line from Sammis Generating Station contributed to the operation of the relay. Prior to the loss of Sammis-Star, operator action to shed load may have been an appropriate action. Subsequent to the Sammis-Star line trip, only automatic protection systems would have mitigated the cascade.

A zone 3 relay can be defined as an impedance relay that is set to detect system faults on the protected transmission line and beyond.⁵ It sometimes serves a dual purpose. It can act through a timer to see faults beyond the next bus up to and including the furthest remote element attached to the bus. It is used for equipment protection beyond the line and it is an alternative to equipment failure communication systems sometimes referred to as breaker failure transfer trip. Zone 3 relays can also be used in the high-speed relaying system for the line. In this application, the relay needs directional intelligence from the other end of the line that it receives via a highly reliable communication system. In the Sammis-Star trip, the zone 3 relay operated because it was set to detect a remote fault on the 138-kV side of a Star substation transformer in the event of a breaker failure.

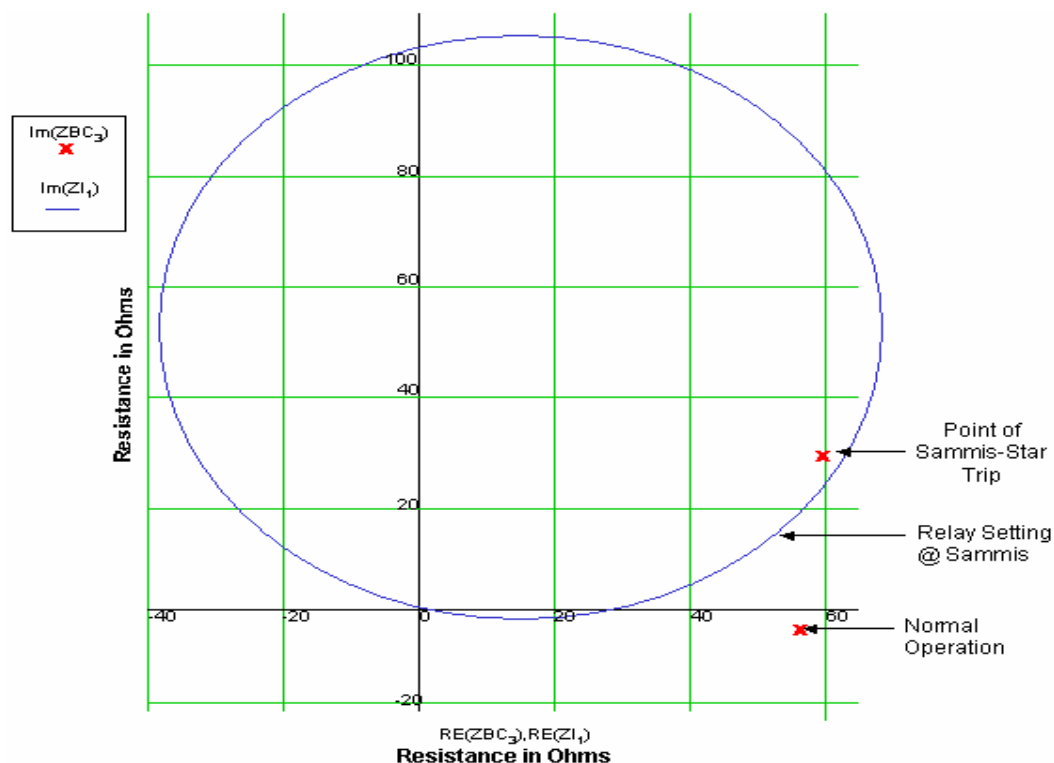


Figure III.9 — Load Encroachment of Sammis-Star Zone 3 Impedance Relay

⁵ Zone 3 in this context means all forward and overreaching distance relays, which could also include zone 2 distance relays.

IV. Cascading Failure of the Power System

Section III described how uncorrected problems in northern Ohio developed to 16:05:57, the last point at which a cascade of line trips could have been averted. The investigation also sought to understand how and why the cascade spread and stopped as it did. This section details the sequence of events in the cascade, how and why it spread, and how it stopped in each geographic area.

The cascade spread beyond Ohio and caused a widespread blackout for three principal reasons. First, the loss of the Sammis-Star line in Ohio, following the loss of other transmission lines and weak voltages within Ohio, triggered many subsequent line trips. Second, many of the key lines that tripped between 16:05:57 and 16:10:38 operated on zone 3 impedance relays (or zone 2 relays set to operate like zone 3s), which responded to overloads rather than faults on the protected facilities. The speed at which they tripped accelerated the spread of the cascade beyond the Cleveland-Akron area. Third, the evidence indicates that the relay protection settings for the transmission lines, generators, and underfrequency load-shedding in the Northeast may not be sufficient to reduce the likelihood and consequences of a cascade, nor were they intended to do so. These issues are discussed in depth below.

This analysis is based on close examination of the events in the cascade, supplemented by dynamic simulations of the electrical phenomena that occurred. At the completion of this report, the modeling had progressed through 16:11:00, and was continuing. Thus, this section is informed and validated by modeling up until that time. Explanations after that time reflect the investigation team's best hypotheses given the available data, and may be confirmed or modified when the modeling is complete. Final modeling results will be published as a technical report at a later date.

A. How the Cascade Evolved

A series of line outages in northeastern Ohio starting at 15:05 caused heavy loadings on parallel circuits, leading to the trip and lock-out of the Sammis-Star line at 16:05:57. This was the event that triggered a cascade of line outages on the high voltage system, causing electrical fluctuations and generator trips such that within seven minutes the blackout rippled from the Cleveland-Akron area across much of the northeastern United States and Canada. By 16:13, more than 508 generating units at 265 power plants had been lost, and tens of millions of people in the United States and Canada were without electric power.

The events in the cascade started slowly, but spread quickly. Figure IV.1 illustrates how the number of lines and generators lost stayed relatively low during the Ohio phase of the blackout, but then picked up speed after 16:08:59. The cascade was complete only two-and-one-half minutes later.

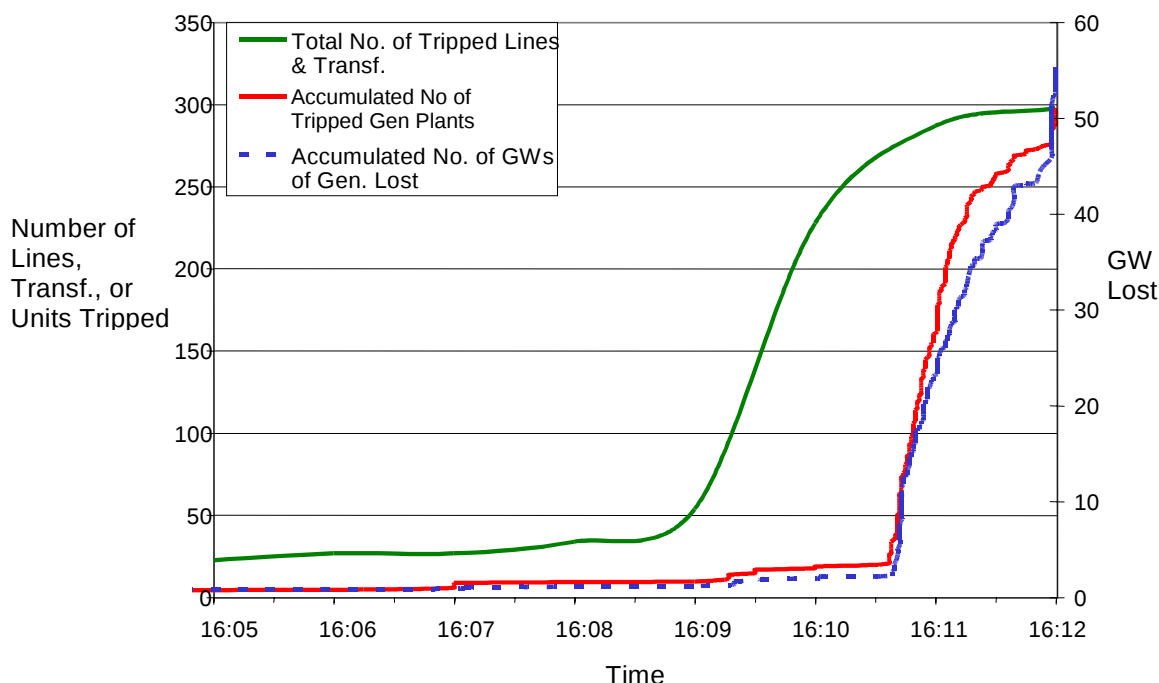


Figure IV.1 — Accumulated Line and Generator Trips During the Cascade

The collapse of the FE transmission system induced unplanned shifts of power across the region. Shortly before the collapse, large (but normal) electricity flows were moving through the FE system from generators in the south (Tennessee and Kentucky) and west (Illinois and Missouri) to load centers in northern Ohio, eastern Michigan, and Ontario. Once the 345-kV and 138-kV system outages occurred in the Cleveland-Akron area, power that was flowing into that area over those lines shifted onto lines to the west and the east. The rapid increase in loading caused a series of lines within northern Ohio to trip on zone 3 impedance relays. A “ripping” effect occurred as the transmission outages propagated west across Ohio into Michigan. The initial propagation of the cascade can best be described as a series of line trips caused by sudden, steady state power shifts that overloaded other lines — a “domino” effect.

The line trips progressed westward across Ohio, then northward into Michigan, separating western and eastern Michigan, causing a 500 MW power reversal within Michigan toward Cleveland. Many of these line trips were caused by zone 3 impedance relay actions that accelerated the speed of the line trips. With paths cut from the west, a massive power surge flowed from PJM into New York and Ontario in a counter-clockwise flow around Lake Erie to serve the load still connected in eastern Michigan and northern Ohio. Transient instability began after 16:10:38, and large power swings occurred. First, a power surge of 3,700 MW flowed into Michigan across the Canadian border. Then the flow reversed by 5,800 MW within one second and peaked at 2,100 MW from Michigan to Canada. Relays on the lines between PJM and New York saw massive power swings and tripped those lines. Ontario’s east-west tie line also tripped, leaving northwestern Ontario connected to Manitoba and Minnesota.

The entire northeastern United States and eastern Ontario then became a large electrical island separated from the rest of the Eastern Interconnection. The major transmission split initially occurred along the long transmission lines across the Pennsylvania border to New York, and then proceeded into northeastern New Jersey. The resulting large electrical island, which had been importing power prior to the cascade, quickly became unstable after the massive transient swings and system separation. There was not sufficient generation on-line within the island to meet electricity demand. Systems to the south and west of the split, such as PJM, AEP, and others further away, remained intact and were mostly

unaffected by the outage. Once the Northeast split from the rest of the Eastern Interconnection, the cascade was isolated to that portion of the Interconnection.

In the final phase, after 16:10:46, the large electrical island in the northeast had less generation than load, and was unstable with large power surges and swings in frequency and voltage. As a result, many lines and generators across the disturbance area tripped, breaking the area into several electrical islands. Generation and load within most of the smaller islands were unbalanced, leading to further tripping of lines and generating units until equilibrium was established in each island. Although much of the disturbance area was fully blacked out in this process, some islands were able to reach equilibrium between generation and load without a total loss of service. For example, the island consisting of most of New England and the Maritime provinces stabilized, and generation and load returned to balance. Another island consisted of load in western New York and a small portion of Ontario, supported by some New York generation, the large Beck and Saunders plants in Ontario, and the 765-kV interconnection to Québec. These two large islands survived but other areas with large load centers collapsed into a blackout condition (Figure IV.2).

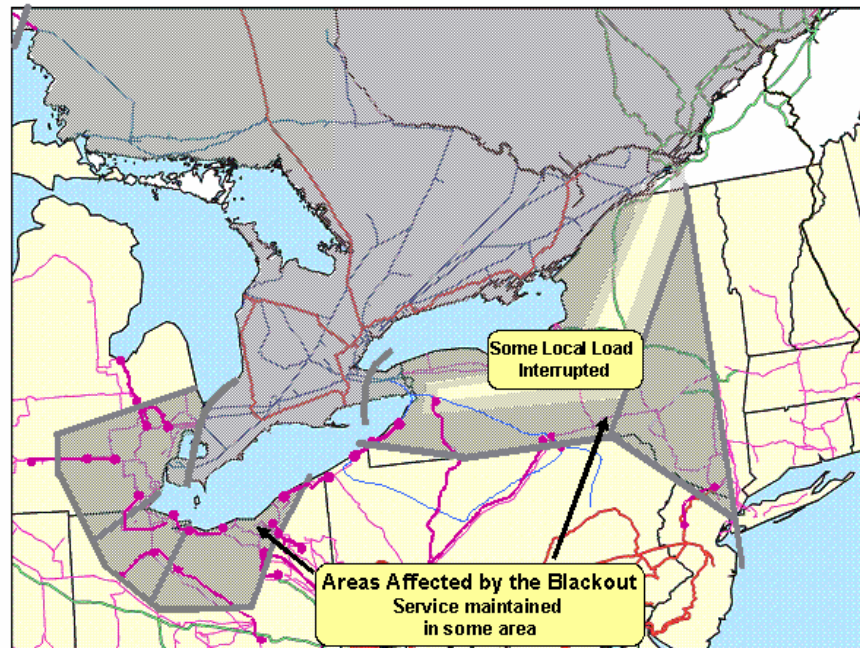


Figure IV.2 — Area Affected by the Blackout

B. Transmission System Cascade in Northern Ohio and South-Central Michigan

1. Overview

After the loss of Sammis-Star and the underlying 138-kV system, there were no large capacity transmission lines left from the south to support the significant amount of load in northern Ohio (Figure IV.3). This overloaded the transmission paths west and northwest into Michigan, causing a sequential loss of lines and power plants.

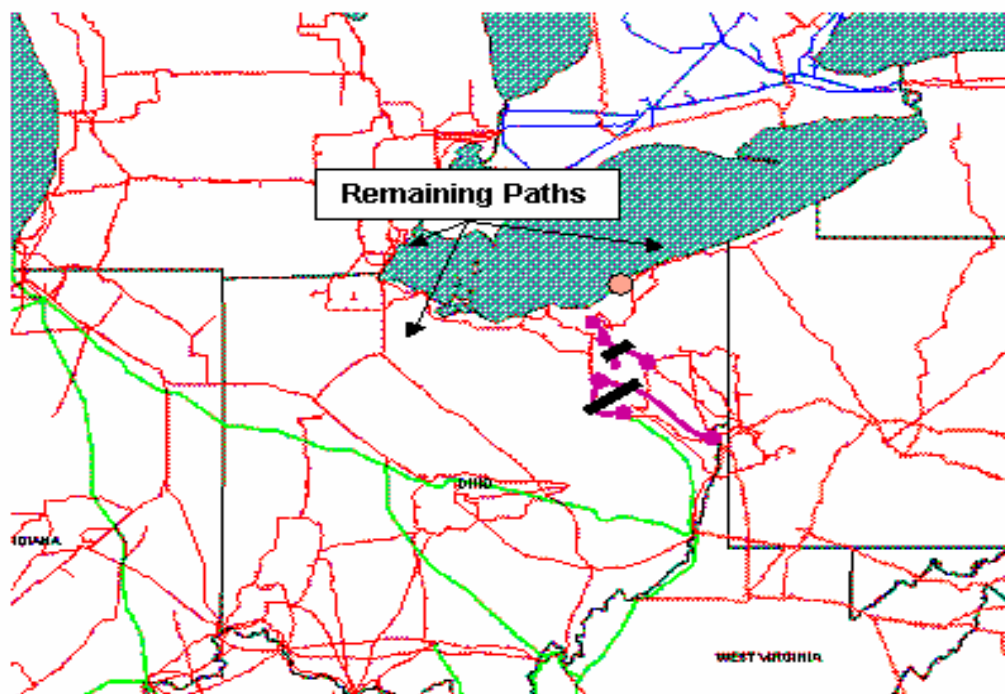


Figure IV.3 — Sammis-Star 345-kV Line Trip 16:05:57

The key events in this phase of the cascade were:

- 16:05:57: Sammis-Star 345-kV line tripped by zone 3 relay
- 16:08:59: Galion-Ohio Central-Muskingum 345-kV line tripped
- 16:09:06: East Lima-Fostoria Central 345-kV line tripped on zone 3 relay, causing a ripple of power swings through New York and Ontario into Michigan
- 16:09:08 to 16:10:27: Several power plants were lost, totaling 937 MW

C. Sammis-Star 345-kV Trip: 16:05:57 EDT

Sammis-Star did not trip due to a short circuit to ground (as did the prior 345-kV lines that tripped). Sammis-Star tripped due to protective zone 3 relay action that measured low apparent impedance (Figure III.9). There was no fault and no major power swing at the time of the trip; rather, high flows at 130 percent of the line's emergency rating, together with depressed voltages, caused the overload to appear to the protective relays as a remote fault on the system. In effect, the relay could no longer differentiate between a remote three-phase fault and conditions of high loading and low voltage. Moreover, the reactive flows (Vars) on the line were almost ten times higher than they had been earlier in the day because of the degrading conditions in the Cleveland-Akron area. The relay operated as designed.

The Sammis-Star trip completely severed the 345-kV path into northern Ohio from southeastern Ohio, triggering a new, fast-paced sequence of 345-kV transmission line trips in which each line trip placed a greater flow burden on those lines remaining in service. These line outages left only three paths for power to flow into western Ohio: (1) from northwestern Pennsylvania to northern Ohio around the south shore of Lake Erie, (2) from southwestern Ohio toward northeastern Ohio, and (3) from eastern Michigan and Ontario. The line interruptions substantially weakened northeast Ohio as a source of power to eastern

Michigan, making the Detroit area more reliant on 345-kV lines west and northwest of Detroit, and from northwestern Ohio to eastern Michigan.

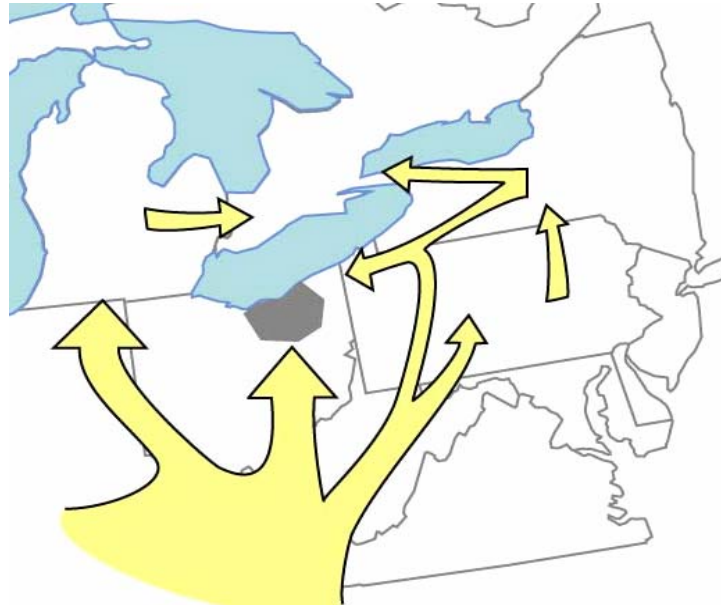


Figure IV.4 — Power Flows at 16:05:57, Prior to the Sammis-Star Trip

Soon after the Sammis-Star trip, four of the five 48 MW Handsome Lake combustion turbines in western Pennsylvania tripped off-line. These units are connected to the 345-kV system by the Homer City-Wayne 345-kV line, and were operating that day as synchronous condensers to participate in PJM's spinning reserve market (not to provide voltage support). When Sammis-Star tripped and increased loadings on the local transmission system, the Handsome Lake units were close enough electrically to sense the impact and tripped off-line at 16:07:00 on under-voltage relay protection.

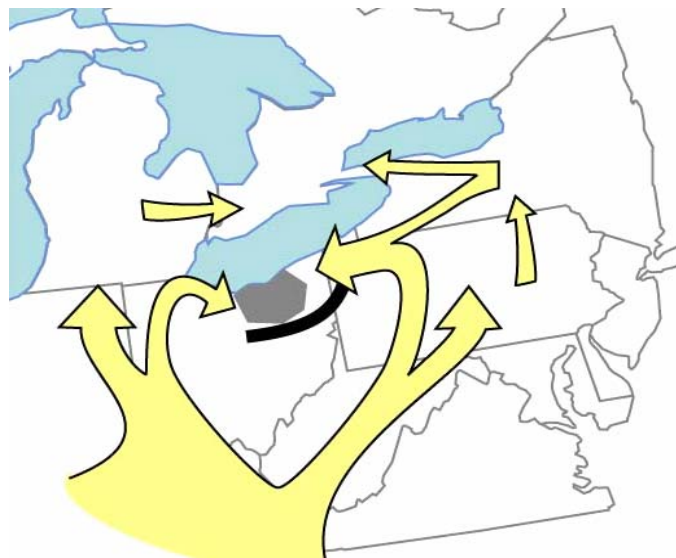


Figure IV.5 — Power Flows at 16:05:58, After the Sammis-Star Trip

During the period between the Sammis-Star trip and the trip of East Lima-Fostoria 345-kV line at 16:09:06.3, the system was still in a steady-state condition. Although one line after another was overloading and tripping within Ohio, this was happening slowly enough under relatively stable conditions that the system could readjust; after each line loss, power flows would redistribute across the remaining lines. This is illustrated in Figure IV.6, which shows the megawatt flows on the MECS interfaces with AEP (Ohio), FE (Ohio), and Ontario. The graph shows a shift from 150 MW of imports to 200 MW of exports from the MECS system into FE at 16:05:57 after the loss of Sammis-Star, after which this held steady until 16:08:59, when the loss of East Lima-Fostoria Central cut the main energy path from the south and west into Cleveland and Toledo. Loss of this path was significant, causing flow from MECS into FE to jump from 200 MW up to 2,300 MW, where it swung dynamically before stabilizing.

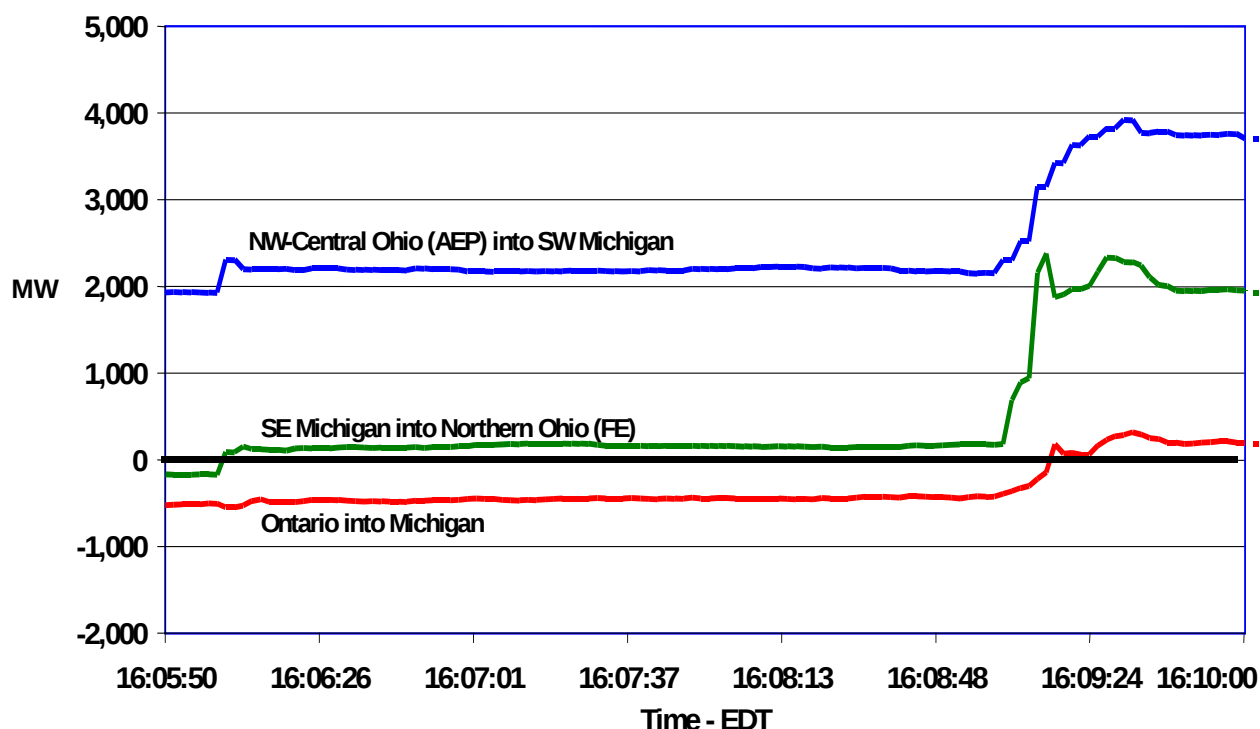


Figure IV.6 — Line Flows Into Michigan

1. Line Trips Westward across Ohio and Generator Trips in Michigan and Ohio: 16:08:59 to 16:10:27 EDT

Key events in this portion of the cascade are:

- 16:08:59: Galion-Ohio Central-Muskingum 345-kV line tripped
- 16:09:06: East Lima-Fostoria Central 345-kV line tripped, causing a large power swing from Pennsylvania and New York through Ontario to Michigan

The Muskingum-Ohio Central-Galion line tripped first at Muskingum at 16:08:58.5 on a phase-to-ground fault. The line reclosed and tripped again at 16:08:58.6 at Ohio Central. The line reclosed a second time and tripped again at Muskingum on a zone 3 relay. Finally, the line tripped and locked open at Galion on a low magnitude B Phase ground fault. After the Muskingum-Ohio Central-Galion line outage and

numerous 138-kV line trips in central Ohio, the East Lima-Fostoria Central line tripped at 16:09:06 on zone 3 relay operation due to high current and low voltage (80 percent). Modeling indicates that if automatic under-voltage load-shedding had been in place in northeastern and central Ohio, it might have been triggered at or before this point and dropped enough load to reduce or eliminate the subsequent line overloads that spread the cascade. The line trips across Ohio are shown in figure IV.7.

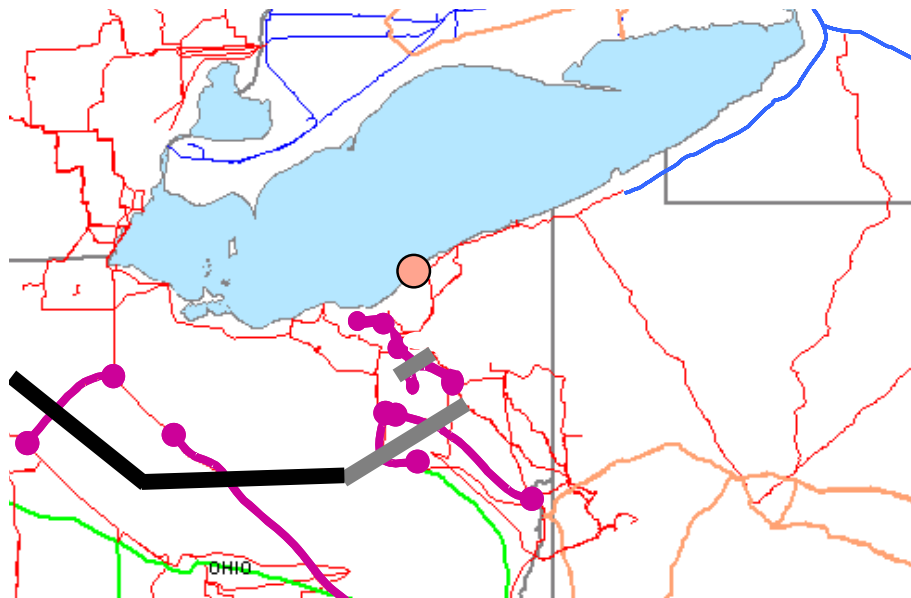


Figure IV.7 — Ohio 345-kV Lines Trip, 16:08:59 to 16:09:07

The tripping of the Galion-Ohio Central-Muskingum and East Lima-Fostoria Central transmission lines removed the transmission paths from southern and western Ohio into northern Ohio and eastern Michigan. Northern Ohio was connected to eastern Michigan by only three 345-kV transmission lines near the southwestern bend of Lake Erie. Thus, the combined northern Ohio and eastern Michigan load centers were left connected to the rest of the grid only by: (1) transmission lines eastward from northeastern Ohio to northwestern Pennsylvania along the southern shore of Lake Erie, and (2) westward by lines west and northwest of Detroit, Michigan, and from Michigan into Ontario (Figure IV.8).

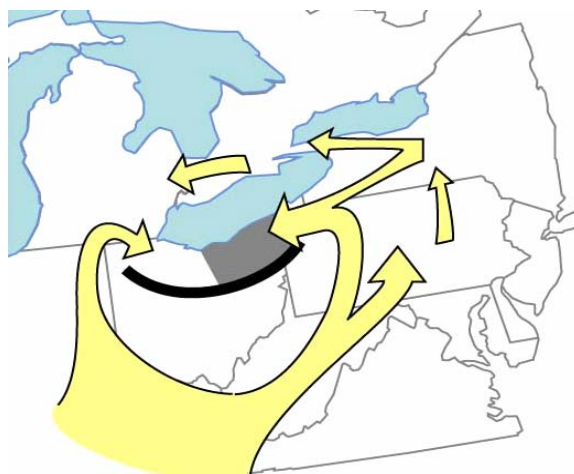


Figure IV.8 — Power Flows at 16:09:25

Although the blackout of August 14 has been labeled by some as a voltage collapse, it was not a voltage collapse as that term has been traditionally used by power system engineers. Voltage collapse occurs when an increase in load or loss of generation or transmission facilities causes voltage to drop, which causes a further reduction in reactive power from capacitors and line charging, and still further voltage reductions. If the declines continue, these voltage reductions cause additional elements to trip, leading to further reduction in voltage and loss of load. The result is a progressive and uncontrollable decline in voltage because the power system is unable to provide the reactive power required to supply the reactive power demand. This did not occur on August 14. While the Cleveland-Akron area was short of reactive power reserves, there was sufficient reactive supply to meet the reactive power demand in the area and maintain stable albeit depressed 345-kV voltage for the outage conditions experienced from 13:31 to 15:32. This included the first forced outage at 13:31 (Eastlake 5 trip) to the third contingency at 15:32 (Hanna-Juniper trip). Only after the fourth contingency, the lockout of South Canton-Star at 15:42, did the 345-kV voltage drop below 90 percent at the Star substation.

As the cascade progressed beyond Ohio, it did not spread due to insufficient reactive power and a voltage collapse, but because of large line currents with depressed voltages, dynamic power swings when the East Lima-Fostoria Central line trip separated southern Ohio from northern Ohio, and the resulting transient instability after northern Ohio and eastern Michigan were isolated onto the Canadian system.

Figure IV.9 shows voltage levels recorded in the Niagara area. It shows that voltage levels remained stable until about 16:10:30, despite significant power fluctuations. In the cascade that followed, the voltage instability was a companion to, not a driver of, the angular instability that tripped generators and lines. A high-speed recording of 345-kV flows at Niagara Falls taken by the Hydro One recorders (shown as the lower plot in Figure IV.9), shows the impact of the East Lima-Fostoria Central and the New York-to-Ontario power swing, which continued to oscillate for more than ten seconds. Looking at the MW flow plot, it is clear that when Sammis-Star tripped, the system experienced oscillations that quickly damped out and rebalanced. But East Lima-Fostoria triggered significantly greater oscillations that worsened in magnitude for several cycles, and then dampened more slowly but continued to oscillate until the Argenta-Battle Creek trip 90 seconds later. Voltages also began to decline at that time.

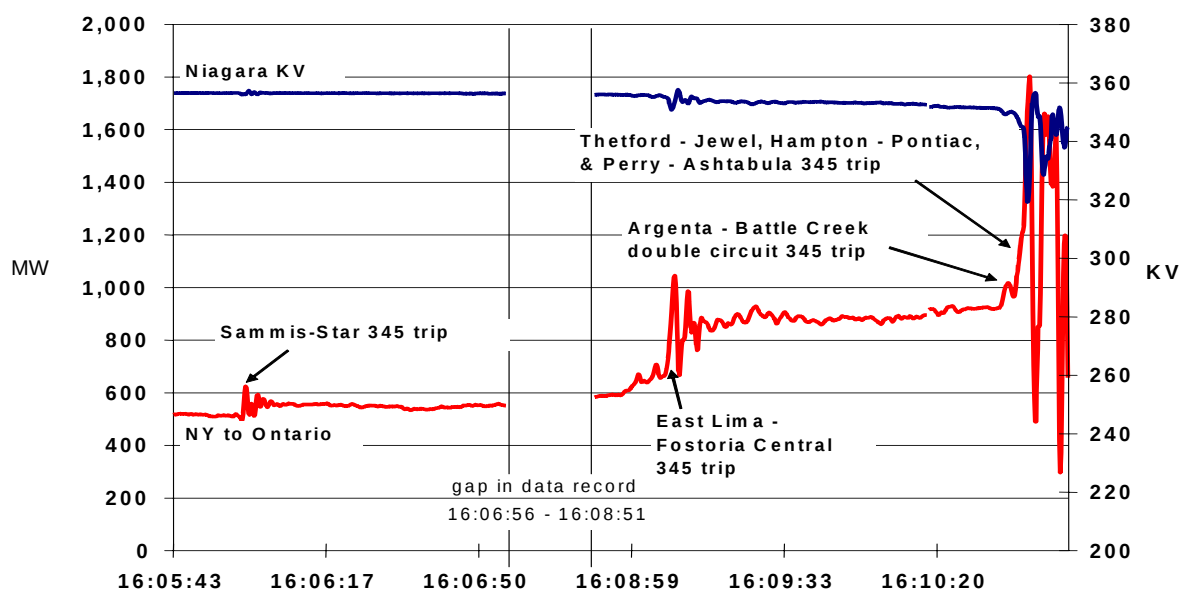


Figure IV.9 — New York-Ontario Line Flows at Niagara

After the East Lima-Fostoria Central trip, power flows increased dramatically and quickly on the lines into and across southern Michigan. Although power had initially been flowing northeast out of Michigan into Ontario, that flow suddenly reversed and approximately 500 to 700 MW of power flowed southwest out of Ontario through Michigan to serve the load of Cleveland and Toledo. This flow was fed by 700 MW pulled out of PJM through New York on its 345-kV network. This was the first of several inter-area power and frequency events that occurred over the next two minutes. This was the system's response to the loss of the northwestern Ohio transmission paths, and the stress that the Cleveland, Toledo, and Detroit loads put onto the surviving lines and local generators.

The far right side of Figure IV.9 shows the fluctuations in flows and voltages at the New York-Ontario Niagara border triggered by the trips of the Argenta-Battle Creek, Argenta-Tompkins, Hampton-Pontiac, and Thetford-Jewell 345-kV lines in Michigan, and the Erie West-Ashtabula-Perry 345-kV line linking the Cleveland area to Pennsylvania. Farther south, the very low voltages on the northern Ohio transmission system made it difficult for the generation in the Cleveland and Lake Erie area to remain synchronous with southeast Michigan. Over the next two minutes, generators in this area shut down after reaching a point of no recovery as the stress level across the remaining ties became excessive.

Figure IV.10, showing metered power flows along the New York interfaces, documents how the flows heading north and west toward Detroit and Cleveland varied at three different New York interfaces. Beginning at 16:09:05, power flows jumped simultaneously across all three interfaces; but when the first power surge peaked at 16:09:09, the change in flow was highest on the PJM interface and lowest on the New England interface. Power flows increased significantly on the PJM-New York and New York-Ontario interfaces because of the redistribution of flow around Lake Erie to serve the loads in northern Ohio and eastern Michigan. The New England and Maritimes systems maintained the same generation-to-load balance and did not carry the redistributed flows because they were not in the direct path of the flows. Therefore, the New England-New York interface flows showed little response.

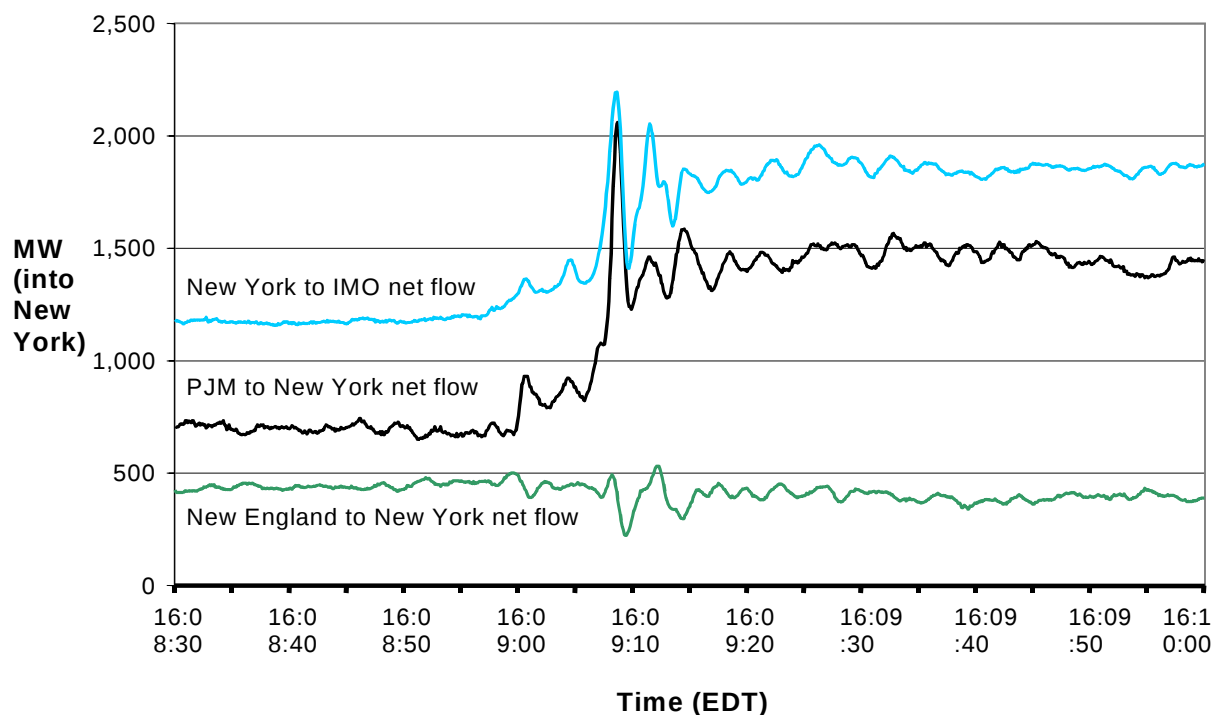


Figure IV.10 — First Power Swing has Varying Impacts on New York Interfaces

Before this first major power swing on the Michigan/Ontario interface, power flows in the NPCC Region (Québec, Ontario and the Maritimes, New England, and New York) were typical for the summer period and well within acceptable limits. Up until this time, transmission and generation facilities were in a secure state across the NPCC region.

2. Loss of Generation Totaling 946 MW: 16:09:08 to 16:10:27 EDT

The following generation was lost from 16:09:08 to 16:10:27 (Figure IV.11):

- 16:09:08: Michigan Cogeneration Venture (MCV) plant run back of 300 MW (from 1,263 MW to 963 MW)
- 16:09:15: Avon Lake 7 unit tripped (82 MW)
- 16:09:17: Burger 3, 4, and 5 units tripped (355 MW total)
- 16:09:23 to 30: Kinder Morgan units 3, 6, and 7 tripped (209 MW total)

The MCV plant in central Michigan experienced a 300 MW run-back. The Avon Lake 7 unit tripped due to the loss of the voltage regulator. The Burger units tripped after the 138-kV lines from the Burger 138-kV generating substation bus to substations in Ohio tripped from high reactive power flow due to the low voltages in the Cleveland area. Three units at the Kinder Morgan generating station in south-central Michigan tripped due to a transformer fault and over-excitation.

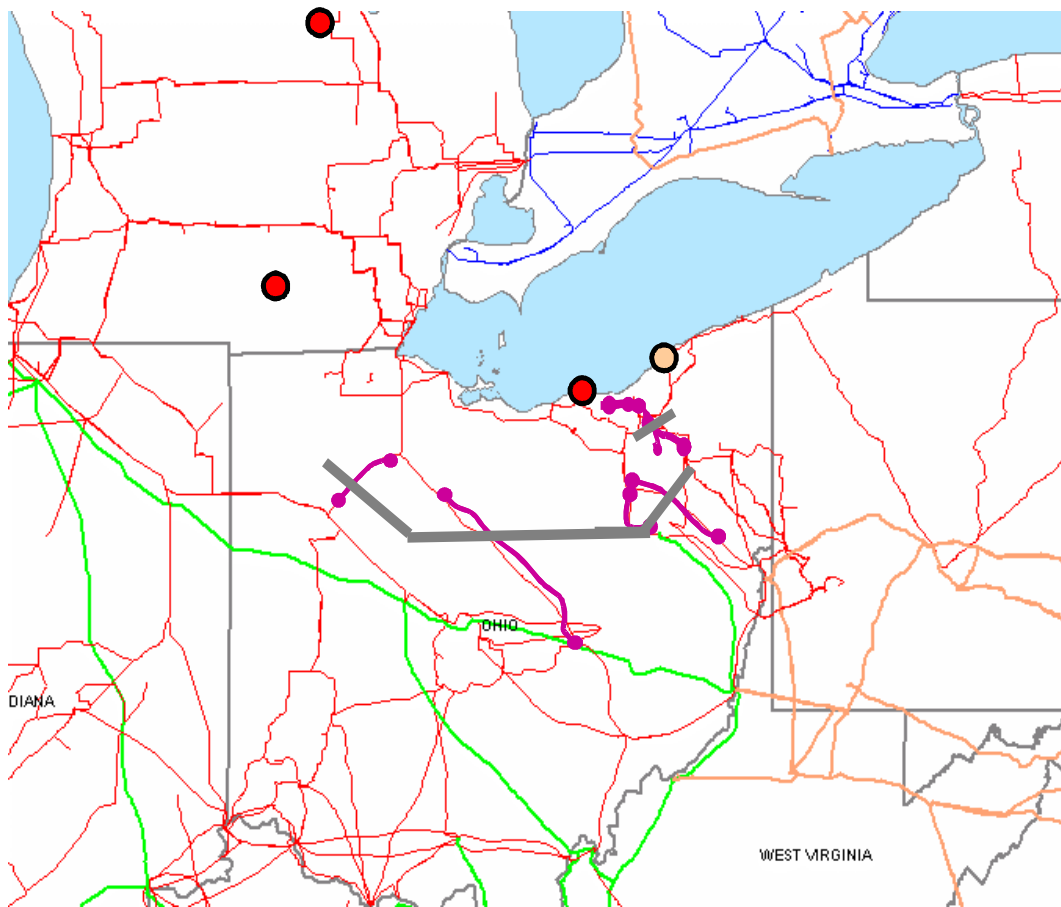


Figure IV.11 — Michigan and Ohio Power Plants Trip or Run Back

Power flows into Michigan from Indiana increased to serve loads in eastern Michigan and northern Ohio (still connected to the grid through northwest Ohio and Michigan) and voltages dropped from the imbalance between high loads and limited transmission and generation capability.

D. High Speed Cascade

Between 16:10:36 and 16:13, a period of less than a minute and a half, a chain reaction of thousands of events occurred on the grid, driven by physics and automatic equipment operations. When it was over, much of the Northeast was in the dark.

1. Transmission and Generation Trips in Michigan: 16:10:36 to 16:10:37 EDT

The following key events occurred as the cascade propagated from Ohio and sliced through Michigan:

- 16:10:36.2: Argenta-Battle Creek 345-kV line tripped
- 16:10:36.3: Argenta-Tompkins 345-kV line tripped
- 16:10:36.8: Battle Creek-Oneida 345-kV line tripped
- 16:10:37: Sumpter Units 1, 2, 3, and 4 units tripped on under-voltage (300 MW near Detroit)
- 16:10:37.5: MCV Plant output dropped from 944 MW to 109 MW on over-current protection

Together, the above line outages interrupted the west-to-east transmission paths into the Detroit area from south-central Michigan. The Sumpter generating units tripped in response to under-voltage on the system. Michigan lines west of Detroit then began to trip, as shown in Figure IV.12.

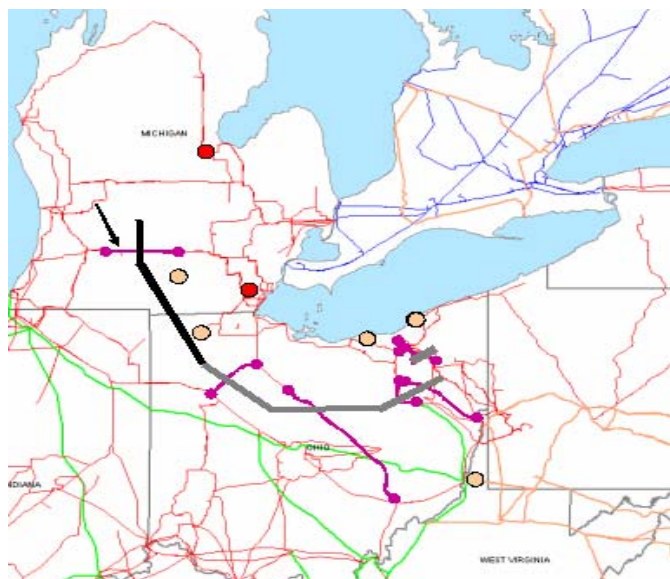


Figure IV.12 — Transmission and Generation Trips in Eastern Michigan, 16:10:36 to 16:10:37

The Argenta-Battle Creek relay first opened the line at 16:10:36.230. The line reclosed automatically at 16:10:37, then tripped again. This line connects major generators — including the Cook and Palisades nuclear plants and the Campbell fossil plant — to the Eastern MECS system. This line is designed with auto-reclose breakers at each end of the line, which do an automatic high-speed reclose as soon as they open to restore the line to service with no interruptions. Since the majority of faults on the North

American grid are temporary, automatic reclosing can enhance stability and system reliability. However, situations can occur where the power systems behind the two ends of the line could go out of phase during the high-speed reclose period (typically less than 30 cycles, or one half second, to allow the air to de-ionize after the trip to prevent arc re-ignition). To address this and protect generators from the harm that an out-of-synchronism reconnect could cause, it is worth studying whether a synchro-check relay is needed to reclose only when the two ends of a line are within a certain voltage and phase angle tolerance. No such protection was installed at Argenta-Battle Creek. When the line reclosed, there was a 70 degree difference in phase across the circuit breaker reclosing the line. There is no evidence that the reclose harmed the local generators. Power flows following the trip of the central Michigan lines are shown in Figure IV.13.

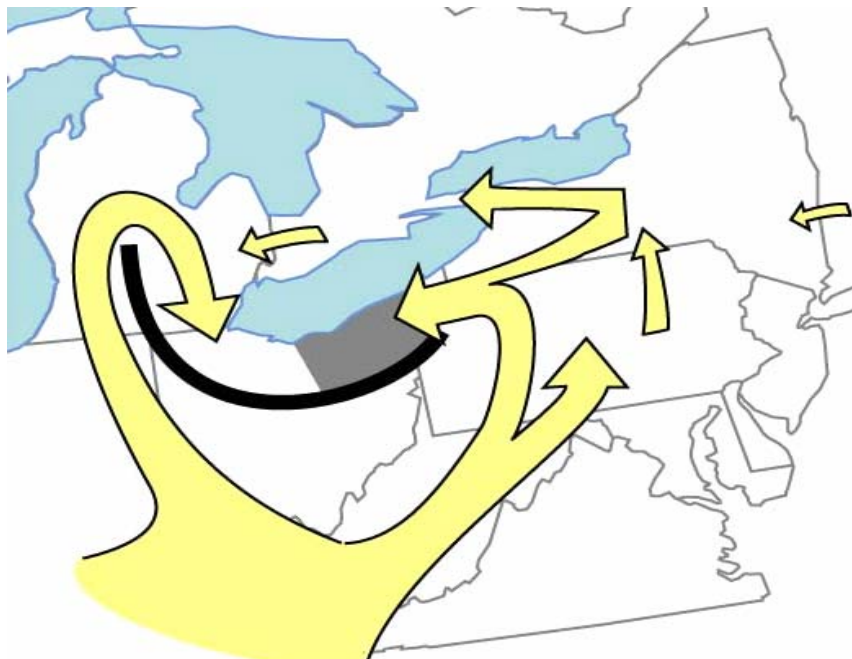


Figure IV.13 — Power Flows at 16:10:37

2. Western and Eastern Michigan Separate: 16:10:37 to 16:10:38 EDT

The following key events occurred at 16:10:37–38:

- 16:10:38.2: Hampton-Pontiac 345-kV line tripped
- 16:10:38.4: Thetford-Jewell 345-kV line tripped

After the Argenta lines tripped, the phase angle between eastern and western Michigan significantly increased. Hampton-Pontiac and Thetford-Jewell were the only lines connecting Detroit to the rest of the grid to the north and west. When these lines tripped out of service, it left the loads in Detroit, Toledo, Cleveland, and their surrounding areas served only by local generation and the lines north of Lake Erie connecting Detroit east to Ontario and the lines south of Lake Erie from Cleveland east to northwestern Pennsylvania. These trips completed the separation of the high voltage transmission system between eastern and western Michigan.

Power system disturbance recorders at Keith and Lambton, Ontario, captured these events in the flows across the Ontario-Michigan interface, as shown in Figure IV.14. The plots show that the west-to-east Michigan separation (culminating with the Thetford-Jewell trip), combined a fraction of a second later with the trip of the Erie West-Ashtabula-Perry 345-kV line connecting Ohio and Pennsylvania, was the

trigger for a sudden 3,700 MW power surge from Ontario into Michigan. When Thetford-Jewell tripped, power that had been flowing into Michigan and Ohio from western Michigan, western Ohio, and Indiana was cut off. The nearby Ontario recorders saw a pronounced impact as flows into Detroit readjusted to flow in from Ontario instead.

On the boundary of northeastern Ohio and northwestern Pennsylvania, the Erie West-Ashtabula-Perry line was the last 345-kV link to the east for northern Ohio loads. When that line severed, all the power that moments before had flowed across Michigan and Ohio paths was now diverted in a counter-clockwise loop around Lake Erie through the single path left in eastern Michigan, pulling power out of Ontario, New York, and PJM.

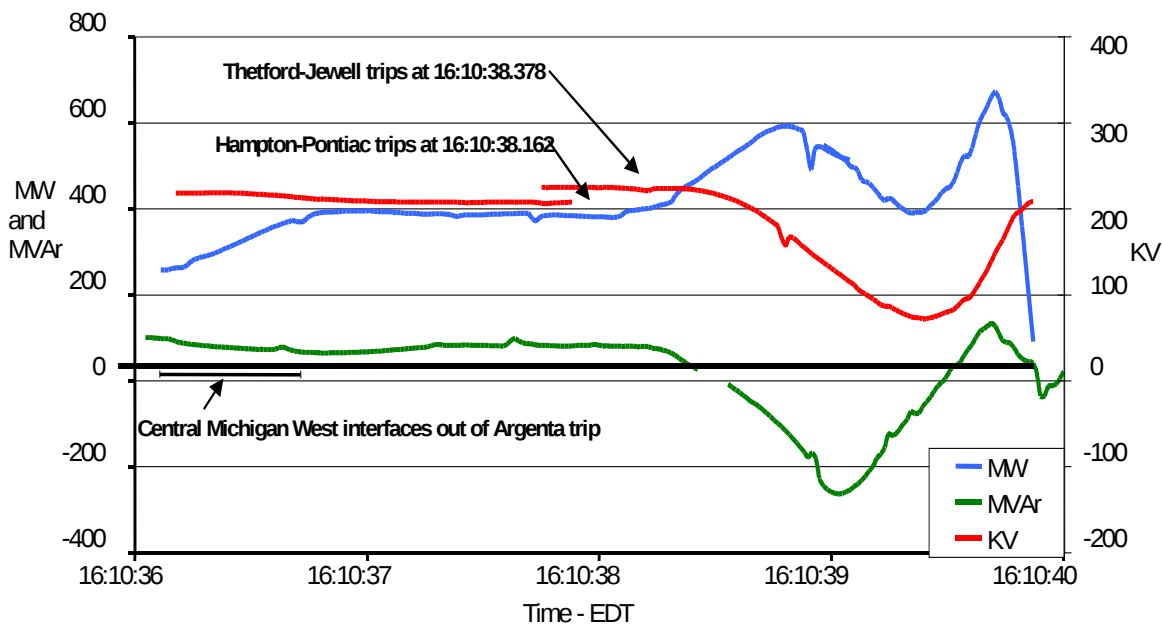


Figure IV.14 — Flows on Keith-Waterman 230-kV Ontario-Michigan Tie Line

Figure IV.15a shows the results of modeling of line loadings on the Ohio, Michigan, and other regional interfaces for the period between 16:05:57 until the Thetford-Jewell trip; this helps to illustrate how power flows shifted during this period. Evolving system conditions were modeled for August 14, based on the 16:05:50 power flow case developed by the MAAC-ECAR-NPCC Operations Studies Working Group. Each horizontal line in the graph indicates a single or set of 345-kV lines and their loading as a function of normal ratings over time as first one, then another, set of circuits tripped out of service. In general, each subsequent line trip causes the remaining line loadings to rise. Note that Muskingum and East Lima-Fostoria Central were overloaded before they tripped, but the Michigan west and north interfaces were not overloaded before they tripped. Erie West-Ashtabula-Perry was loaded to 130 percent after the Hampton-Pontiac and Thetford-Jewell trips.

The regional interface loadings graph (Figure VI.15b) shows that loadings at the interfaces between PJM-New York, New York-Ontario, and New York-New England were well within normal ratings before the east-west Michigan separation.

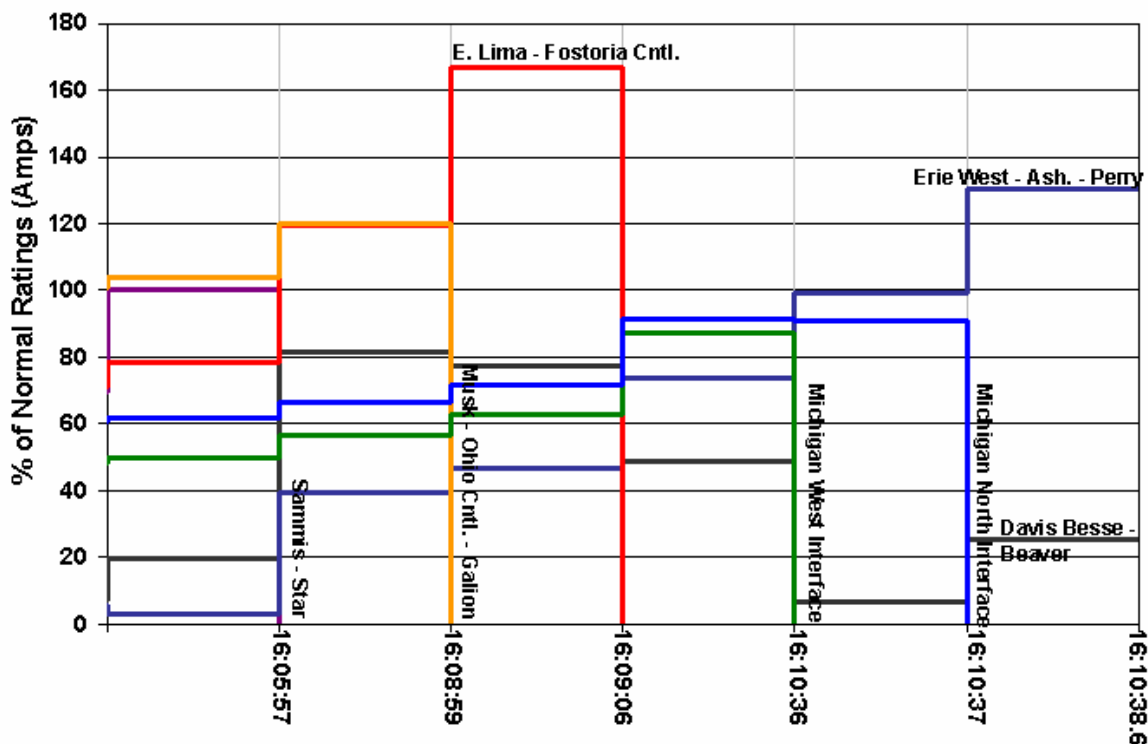


Figure IV.15a — Simulated 345-kV Line Loadings From 16:05:57 Through 16:10:38.6

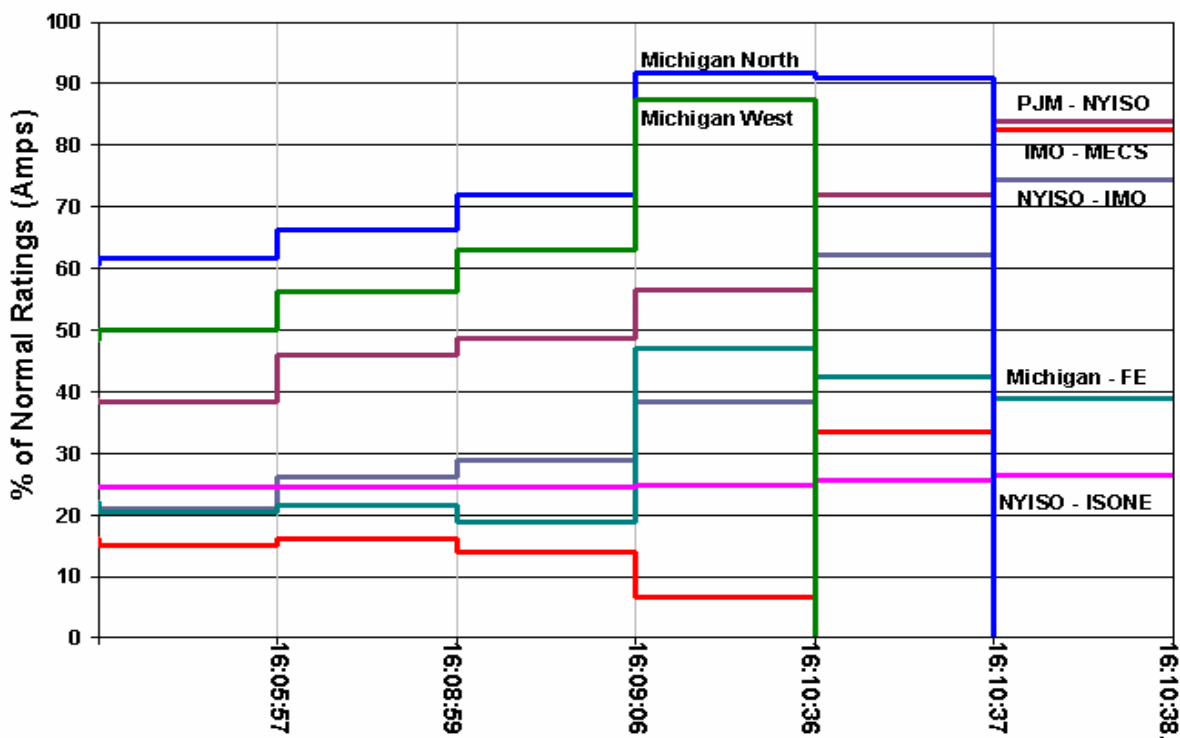


Figure IV.15b — Simulated Regional Interface Loadings From 16:05:57 Through 16:10:38.4

3. Large Counter-clockwise Power Surge around Lake Erie: 16:10:38.6 EDT

The following key events occurred at 16:10:38:

- 16:10:38.2: Hampton-Pontiac 345-kV line tripped
- 16:10:38.4: Thetford-Jewell 345-kV line tripped
- 16:10:38.6: Erie West-Ashtabula-Perry 345-kV line tripped at Perry
- 16:10:38.6: Large power surge to serve loads in eastern Michigan and northern Ohio swept across Pennsylvania, New Jersey, and New York through Ontario into Michigan

Perry-Ashtabula was the last 345-kV line connecting northern Ohio to the east along the southern shore of Lake Erie. This line tripped at the Perry substation on a zone 3 relay operation and separated the northern Ohio 345-kV transmission system from Pennsylvania and all 345-kV connections. After this trip, the load centers in eastern Michigan and northern Ohio (Detroit, Cleveland, and Akron) remained connected to the rest of the Eastern Interconnection only to the north of Lake Erie at the interface between the Michigan and Ontario systems (Figure IV.16). Eastern Michigan and northern Ohio now had little internal generation left and voltage was declining. The frequency in the Cleveland area dropped rapidly, and between 16:10:39 and 16:10:50, underfrequency load shedding in the Cleveland area interrupted about 1,750 MW of load. However, the load shedding was not enough to reach a balance with local generation and arrest the frequency decline. The still-heavy loads in Detroit and Cleveland drew power over the only major transmission path remaining: the lines from eastern Michigan east into Ontario.

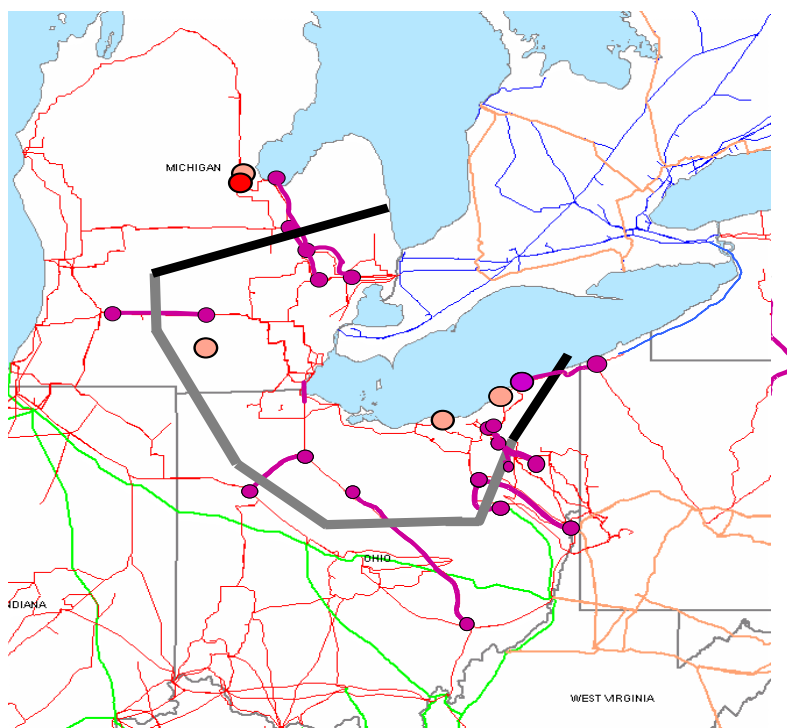


Figure IV.16 — Michigan Lines Trip and Ohio Separates From Pennsylvania, 16:10:36 to 16:10:38.6

At 16:10:38.6, after the 345-kV transmission paths in Michigan and Ohio tripped, the power that had been flowing at modest levels into Michigan from Ontario suddenly jumped in magnitude. While flows from Ontario into Michigan had been in the 250 to 350 MW range since 16:10:09.06, with this new surge the

flows peaked at 3,700 MW at 16:10:39 (Figure IV.17). Electricity moved along a giant loop from the rest of the Eastern Interconnection through Pennsylvania and into New York and Ontario, and then into Michigan via the remaining transmission path to serve the combined loads of Cleveland, Toledo, and Detroit (Figure IV.18). This sudden large change in power flows lowered voltages and increased current levels on the transmission lines along the Pennsylvania-New York transmission interface.

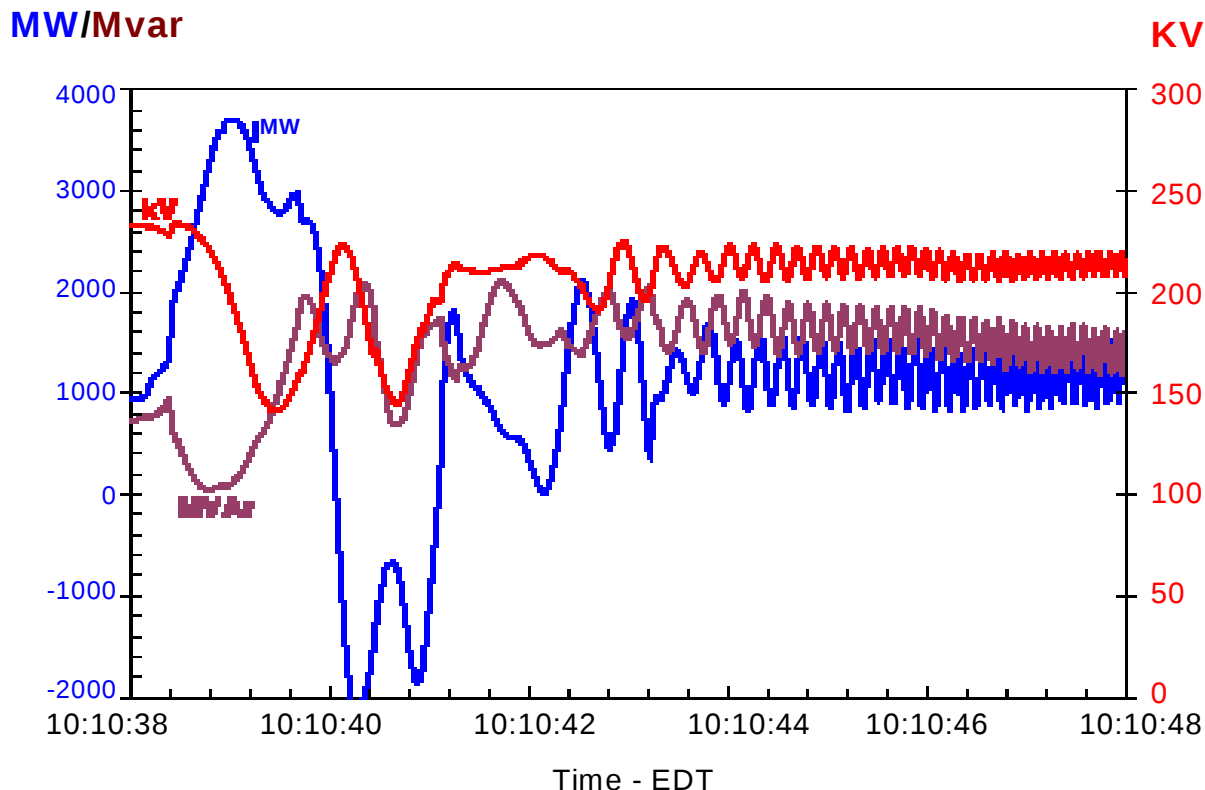


Figure IV.17 — Real and Reactive Power and Voltage From Ontario Into Michigan

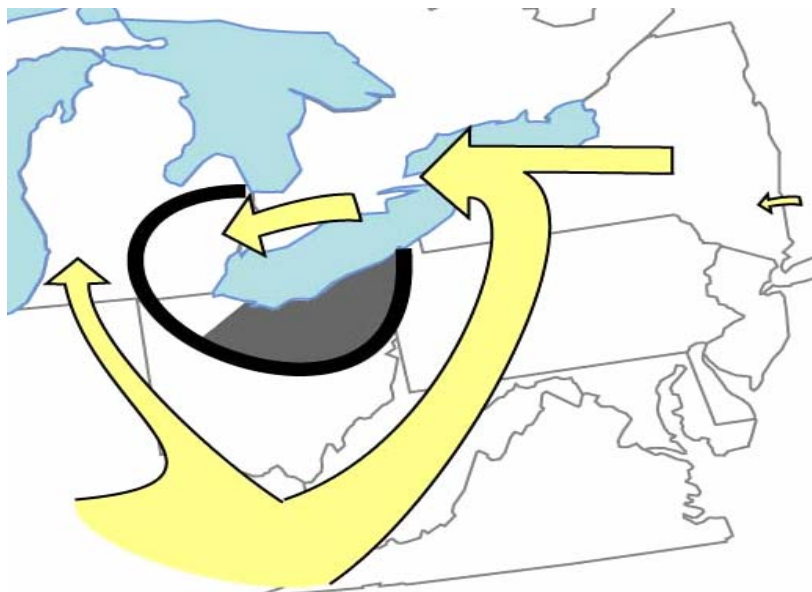


Figure IV.18 — Power Flows at 16:10:39

This power surge was of such a large magnitude that frequency was not the same across the Eastern Interconnection. The power swing resulted in a rapid rate of voltage decay. Flows into Detroit exceeded 3,700 MW and 1,500 Mvar; the power surge was draining real power out of the northeast, causing voltages in Ontario and New York to drop. At the same time, local voltages in the Detroit area were plummeting because Detroit had already lost 500 MW of local generation. The electric system in the Detroit area would soon lose synchronism and black out (as evidenced by the rapid power oscillations decaying after 16:10:43).

Just before the Argenta-Battle Creek trip, when Michigan separated west-to-east at 16:10:37, almost all of the generators in the Eastern Interconnection were operating in synchronism with the overall grid frequency of 60 Hertz, but when the large swing started, those machines began to swing dynamically. After the 345-kV line trip at 16:10:38, the Northeast entered a period of transient instability and loss of generator synchronicity. Between 16:10:38 and 16:10:41, the power swings caused a sudden localized increase in system frequency, hitting 60.7 Hz at Lambton and 60.4 Hz at Niagara.

Because the demand for power in Michigan, Ohio, and Ontario was drawing on lines through New York and Pennsylvania, heavy power flows were moving northward from New Jersey over the New York tie lines to meet those power demands, exacerbating the power swing. Figure IV.19 shows actual net line flows summed across the interfaces between the main regions affected by these swings: Ontario into Michigan, New York into Ontario, New York into New England, and PJM into New York. This shows that the power swings did not move in unison across every interface at every moment, but varied in magnitude and direction. This occurred for two reasons. First, the availability of lines across each interface varied over time, as did the amount of load that drew upon each interface, so net flows across each interface were not facing consistent demand with consistent capability as the cascade progressed. Second, the speed and magnitude of the swing was moderated by the inertia, reactive power capabilities, loading conditions, and locations of the generators across the entire region.

After Cleveland was cut off from Pennsylvania and eastern power sources, Figure IV.19 also shows the start of the dynamic power swing at 16:10:38.6. Because the loads of Cleveland, Toledo, and Detroit (less the load already blacked out) were now served through Michigan and Ontario, this forced a large shift in power flows to meet that demand. As noted above, flows from Ontario into Michigan increased from 1,000 MW to a peak of 3,700 MW shortly after the start of the swing, while flows from PJM into New York were close behind (Figure IV.20). But within one second after the peak of the swing, at 16:10:40, flows reversed and flowed back from Michigan into Ontario at the same time that frequency at the interface dropped (Figure IV.21). The large load and imports into northern Ohio were losing synchronism with southeastern Michigan. Flows that had been westbound across the Ontario-Michigan interface by more than 3,700 MW at 16:10:38.8 reversed to 2,100 MW eastbound by 16:10:40, and then returned westbound starting at 16:10:40.5.

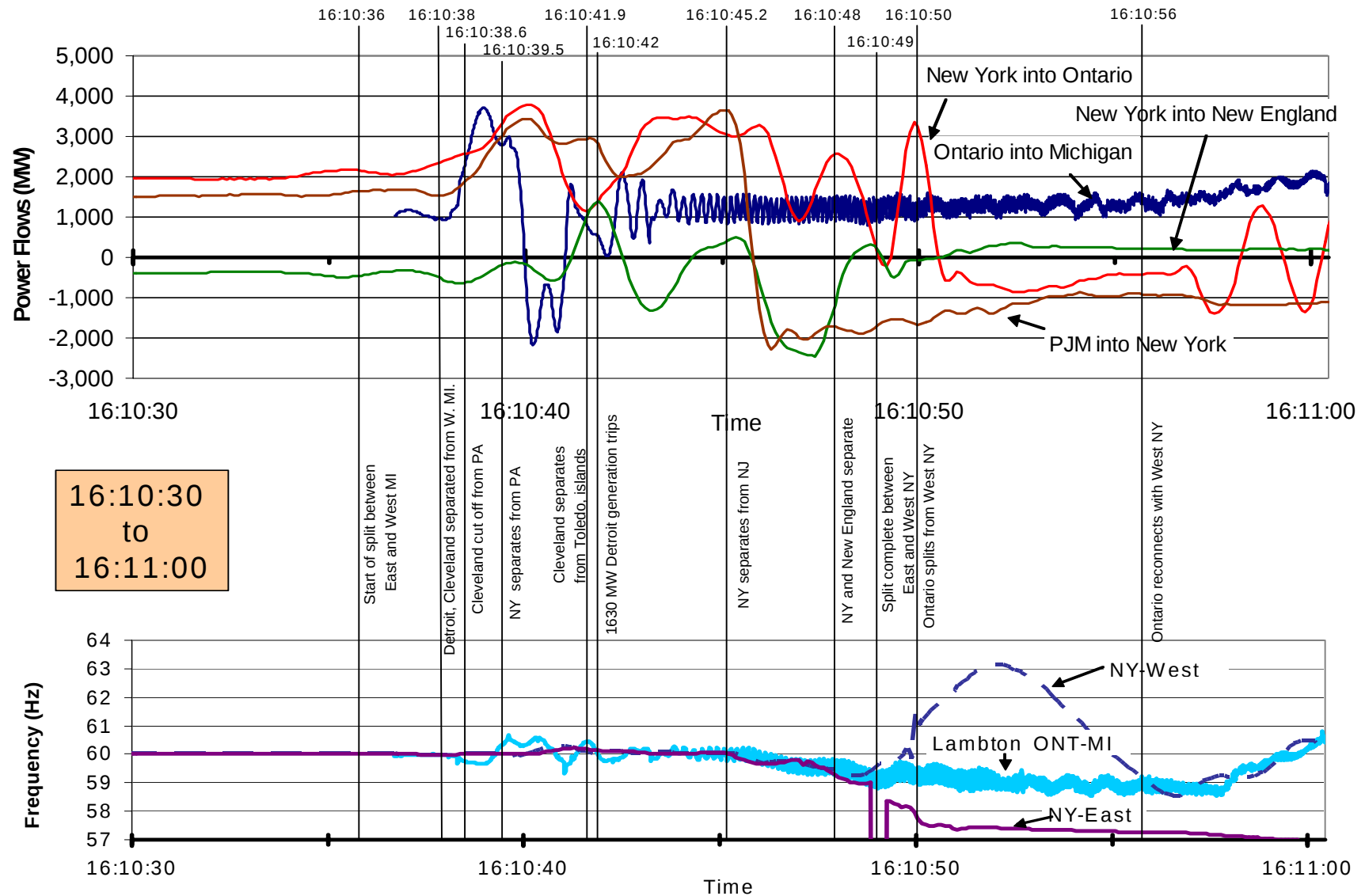


Figure IV.19 — Measured Power Flows and Frequency Across Regional Interfaces, 16:10:30 to 16:11:00, With Key Events in the Cascade

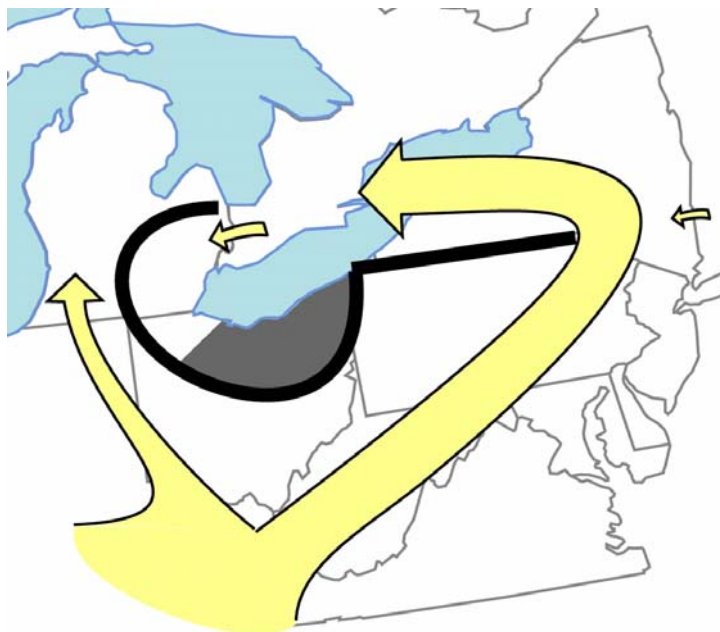


Figure IV.20 — Power Flows at 16:10:40

Two 345-kV lines tripped because of zone 1 relay action along the border between PJM and the NYISO due to the transient overloads and depressed voltage. After the separation from PJM, the dynamic surges also drew power from New England and the Maritimes. The combination of the power surge and frequency rise caused 380 MW of pre-selected Maritimes generation to trip off-line due to the operation of the New Brunswick Power “Loss of Line 3001” Special Protection System. Although this system was designed to respond to failures of the 345-kV link between the Maritimes and New England, it operated in response to the effects of the power surge. The link remained intact during the event.

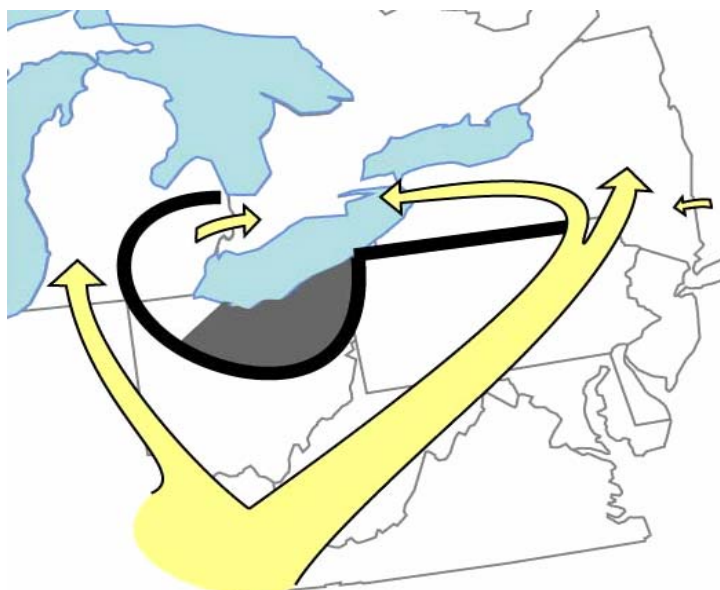


Figure IV.21 — Power Flows at 16:10:41

4. Northern Ohio and Eastern Michigan Systems Degraded Further: 16:10:39 to 16:10:46 EDT

The following events occurred in northern Ohio and eastern Michigan over a period of seven seconds from 16:10:39 to 16:10:46:

Line trips in Ohio and eastern Michigan:

- 16:10:39.5: Bayshore-Monroe 345-kV line
- 16:10:39.6: Allen Junction-Majestic-Monroe 345-kV line
- 16:10:40.0: Majestic-Lemoyne 345-kV line
- Majestic 345-kV Substation: one terminal opened sequentially on all 345-kV lines
- 16:10:41.8: Fostoria Central-Galion 345-kV line
- 16:10:41.911: Beaver-Davis Besse 345-kV line

Underfrequency load shedding in Ohio:

- FirstEnergy shed 1,754 MVA load
- AEP shed 133 MVA load

Six power plants, for a total of 3,097 MW of generation, tripped off-line in Ohio:

- 16:10:42: Bay Shore Units 1–4 (551 MW near Toledo) tripped on over-excitation
- 16:10:40: Lakeshore unit 18 (156 MW, near Cleveland) tripped on underfrequency
- 16:10:41.7: Eastlake 1, 2, and 3 units (304 MW total, near Cleveland) tripped on underfrequency
- 16:10:41.7: Avon Lake unit 9 (580 MW, near Cleveland) tripped on underfrequency
- 16:10:41.7: Perry 1 nuclear unit (1,223 MW, near Cleveland) tripped on underfrequency
- 16:10:42: Ashtabula unit 5 (184 MW, near Cleveland) tripped on underfrequency

Five power plants producing 1,630 MW tripped off-line near Detroit:

- 16:10:42: Greenwood unit 1 tripped (253 MW) on low voltage, high current
- 16:10:41: Belle River unit 1 tripped (637 MW) on out-of-step
- 16:10:41: St. Clair unit 7 tripped (221 MW, DTE unit) on high voltage
- 16:10:42: Trenton Channel units 7A, 8, and 9 tripped (648 MW)
- 16:10:43: West Lorain units (296 MW) tripped on under-voltage

In northern Ohio, the trips of the Bay Shore-Monroe, Majestic-Lemoyne, Allen Junction-Majestic-Monroe 345-kV lines, and the Ashtabula 345/138-kV transformer cut off Toledo and Cleveland from the north, turning that area into an electrical island (Figure IV.22). After these 345-kV line trips, the high power imports from southeastern Michigan into Ohio suddenly stopped at 16:10:40. Frequency in this island began to fall rapidly. This caused a series of power plants in the area to trip off-line due to the operation of underfrequency relays, including the Bay Shore units. Cleveland area load was disconnected by automatic underfrequency load shedding (approximately 1,300 MW), and another 434 MW of load

was interrupted after the generation remaining within this transmission island was tripped by underfrequency relays. This sudden load drop would contribute to the reverse power swing described previously. In its own island, portions of Toledo blacked out from automatic underfrequency load shedding but most of the Toledo load was restored by automatic reclosing of lines such as the East Lima-Fostoria Central 345-kV line and several lines at the Majestic 345-kV substation.

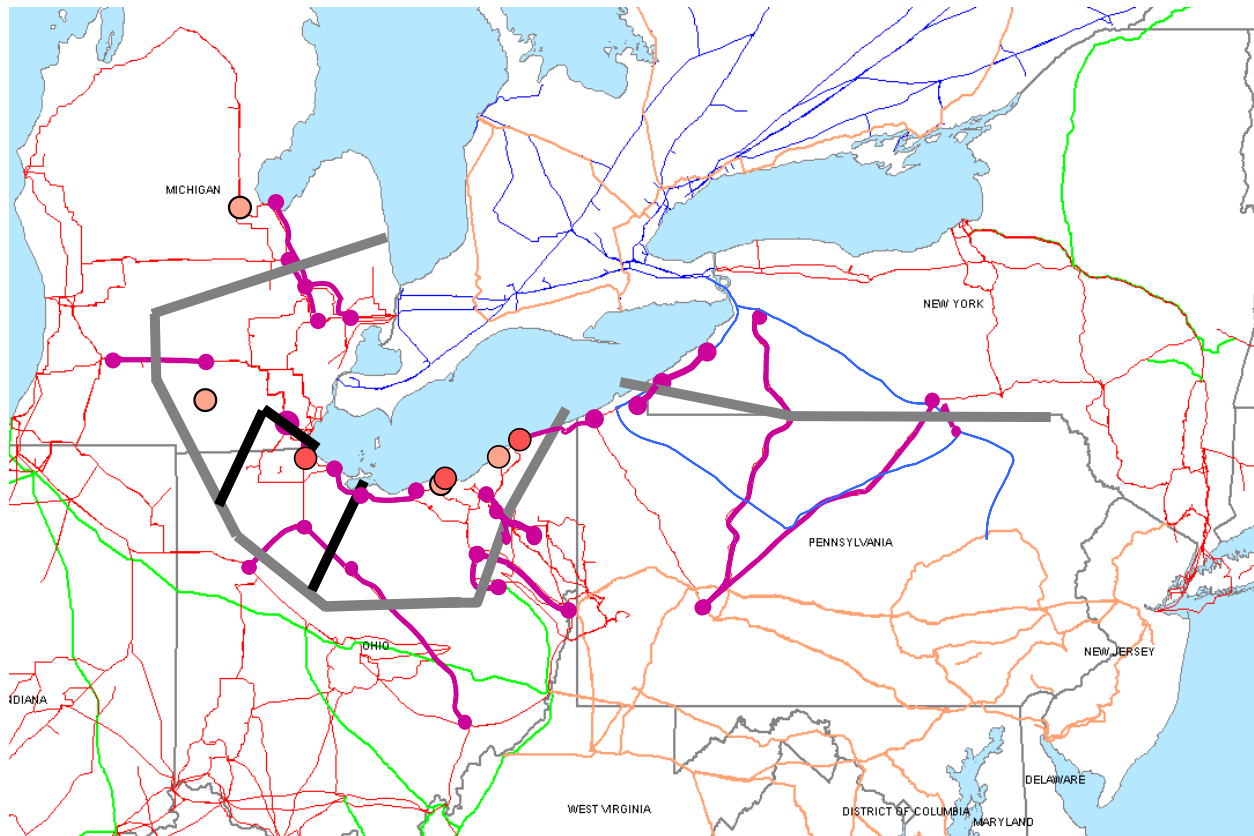


Figure IV.22 — Cleveland and Toledo Islanded, 16:10:39 to 16:10:46

The Perry nuclear plant is located in Ohio on Lake Erie, not far from the Pennsylvania border. The Perry plant was inside the decaying electrical island and tripped soon thereafter on underfrequency, as designed. A number of other units near Cleveland tripped off-line by underfrequency protection. Voltage in the island dropped, causing the Beaver-Davis Besse 345-kV line between Cleveland and Toledo to trip. This marked the end for Cleveland, which could not sustain itself as a separate island. However, by separating from Cleveland, Toledo was able to resynchronize with the rest of the eastern inter-connection once the phase angle across the open East Lima-Fostoria 345-kV line came back within its limits and re-closed.

The large power surge into Michigan, beginning at 16:10:38, occurred when Toledo and Cleveland were still connected to the grid through Detroit. After the Bayshore-Monroe line tripped at 16:10:39, Toledo and Cleveland separated into their own island, dropping a large amount of load off of the Detroit system. This suddenly left Detroit with excess generation, much of which greatly accelerated in angle as the depressed voltage in Detroit (caused by the high demand in Cleveland) caused the Detroit units to begin to pull out of step with the rest of the grid. When voltage in Detroit returned to near-normal, the generators could not sufficiently decelerate to remain synchronous. This out-of-step condition is evident in Figure IV.23, which shows at least two sets of generator “pole slips” by plants in the Detroit area

between 16:10:40 and 16:10:42. Several large units around Detroit: Belle River, St. Clair, Greenwood, Monroe, and Fermi Nuclear all tripped in response. After the Cleveland-Toledo island formed at 16:10:40, Detroit frequency spiked to almost 61.7 Hz before dropping, momentarily equalized between the Detroit and Ontario systems. But Detroit frequency then began to decay at 2 Hz/sec and the generators experienced under-speed conditions.

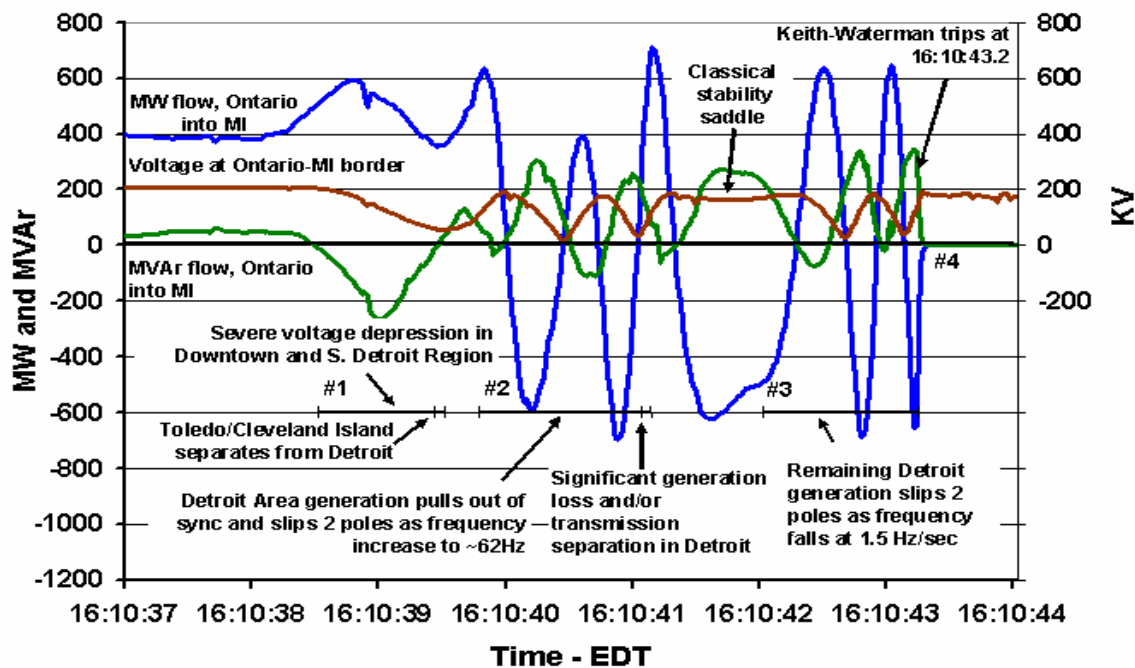


Figure IV.23 — Generators Under Stress in Detroit, as Seen From Keith PSDR

Re-examination of Figure IV.19 shows the power swing from the northeast through Ontario into Michigan and northern Ohio that began at 16:10:37, and how it reverses and swings back around Lake Erie at 16:10:39. That return was caused by the combination of natural oscillation accelerated by major load losses, as the northern Ohio system disconnected from Michigan. It caused a power flow change of 5,800 MW, from 3,700 MW westbound to 2,100 eastbound across the Ontario-to-Michigan border between 16:10:39.5 and 16:10:40. Since the system was now fully dynamic, this large oscillation eastbound would lead naturally to a rebound, which began at 16:10:40 with an inflection point reflecting generation shifts between Michigan and Ontario and additional line losses in Michigan.

5. Western Pennsylvania-New York Separation: 16:10:39 to 16:10:44 EDT

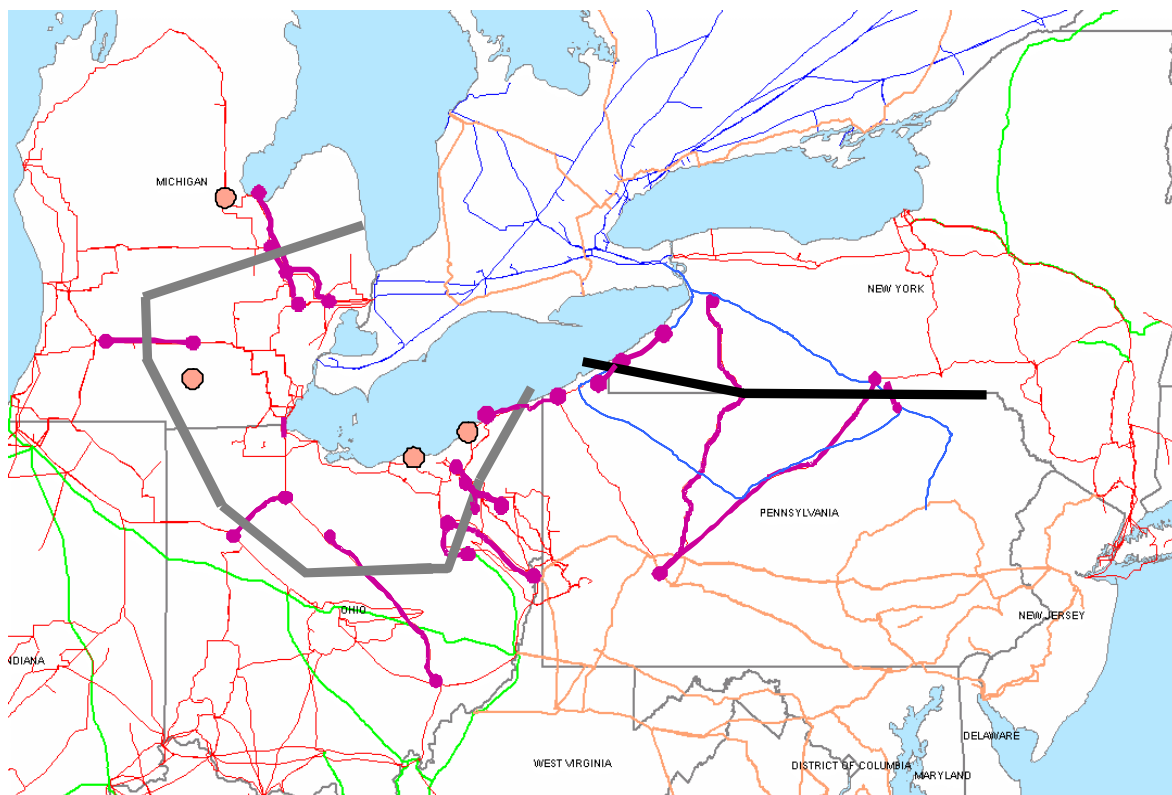
The following events occurred over a five-second period from 16:10:39 to 16:10:44, beginning the separation of New York and Pennsylvania:

- 16:10:39: Homer City-Watercure Road 345-kV
- 16:10:39: Homer City-Stolle Road 345-kV
- 16:10:44: South Ripley-Erie East 230-kV, and South Ripley-Dunkirk 230-kV
- 16:10:44: East Towanda-Hillside 230-kV

Responding to the swing of power out of Michigan toward Ontario and into New York and PJM, zone 1 relays on the 345-kV lines separated Pennsylvania from New York (Figure IV.24). Homer City-

Watercure (177 miles) and Homer City-Stolle Road (207 miles) are relatively long lines with high impedances. Zone 1 relays do not have timers, and therefore operate nearly instantly when a power swing enters the relay target circle. For normal length lines, zone 1 relays have smaller target circles because the relay is measuring less than the full length of the line, but for a long line the greater impedance enlarges the relay target circle and makes it more likely to be hit by the power swing. The Homer City-Watercure and Homer City-Stolle Road lines do not have zone 3 relays.

Given the length and impedance of these lines, it was highly likely that they would trip and separate in the face of such large power swings. Most of the other interfaces between regions have shorter ties. For instance, the ties between New York and Ontario and Ontario to Michigan are only about two miles long, so they are electrically very short and thus have much lower impedance and trip less easily than these long lines. A zone 1 relay target on a short line covers a small distance so a power swing is less likely to enter the relay target circle at all, averting a zone 1 trip.



**Figure IV.24 — Western Pennsylvania Separates From New York,
16:10:39 to 16:10:44**

At 16:10:44, (see Figure IV.25) the northern part of the Eastern Interconnection (including eastern Michigan) was connected to the rest of the Interconnection at only two locations: (1) in the east through the 500-kV and 230-kV ties between New York and northeastern New Jersey, and (2) in the west through the long and electrically fragile 230-kV transmission path connecting Ontario to Manitoba and Minnesota. The separation of New York from Pennsylvania (leaving only the lines from New Jersey into New York connecting PJM to the northeast) helped to buffer PJM in part from these swings. Frequency was high in Ontario at that point, indicating that there was more generation than load, so much of this flow reversal never got past Ontario into New York.

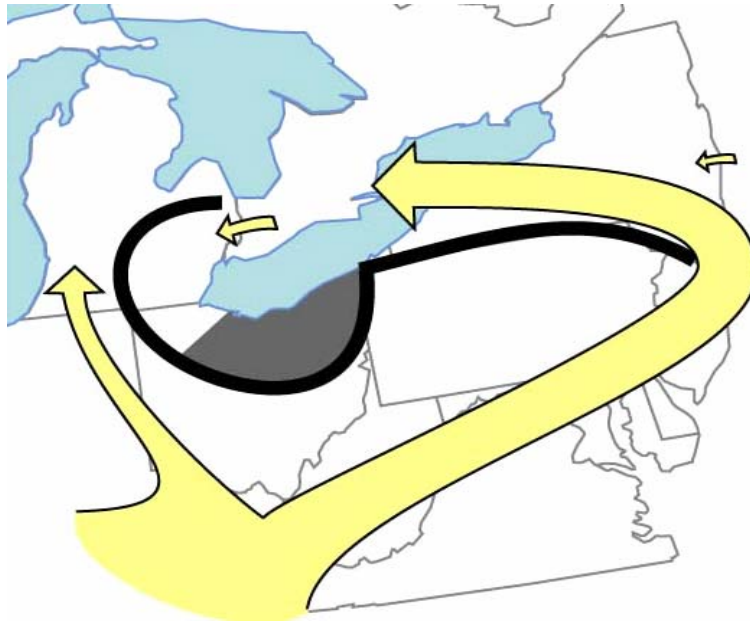


Figure IV.25 — Power Flows at 16:10:44

6. Final Separation of the Northeast from the Eastern Interconnection: 16:10:43 to 16:10:45 EDT

The following line trips between 16:10:43 to 16:10:45 resulted in the northeastern United States and eastern Canada becoming an electrical island completely separated from the rest of the Eastern Interconnection:

- 16:10:43: Keith-Waterman 230-kV line tripped
- 16:10:45: Wawa-Marathon 230-kV lines tripped
- 16:10:45: Branchburg-Ramapo 500-kV line tripped

At 16:10:43, eastern Michigan was still connected to Ontario, but the Keith-Waterman line that forms part of that interface disconnected due to apparent impedance. This put more power onto the remaining interface between Ontario and Michigan, but triggered sustained oscillations in both power flow and frequency along the remaining 230-kV line.

At 16:10:45, northwest Ontario separated from the rest of Ontario when the Wawa-Marathon 230-kV lines (168 km long) disconnected along the northern shore of Lake Superior, tripped by zone 1 distance relays at both ends. This separation left the loads in the far northwest portion of Ontario connected to the Manitoba and Minnesota systems, and protected them from the blackout (Figure IV.26).

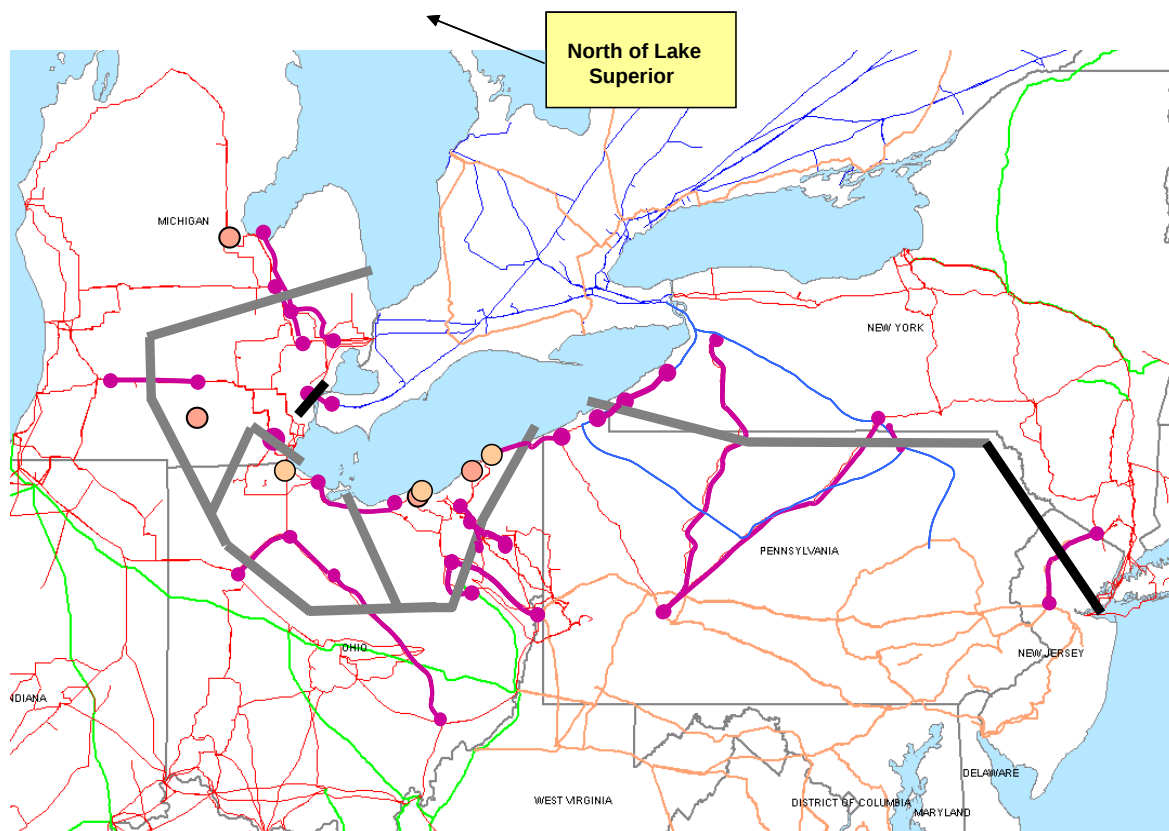


Figure IV.26 — Northeast Separates From Eastern Interconnection, 16:10:45

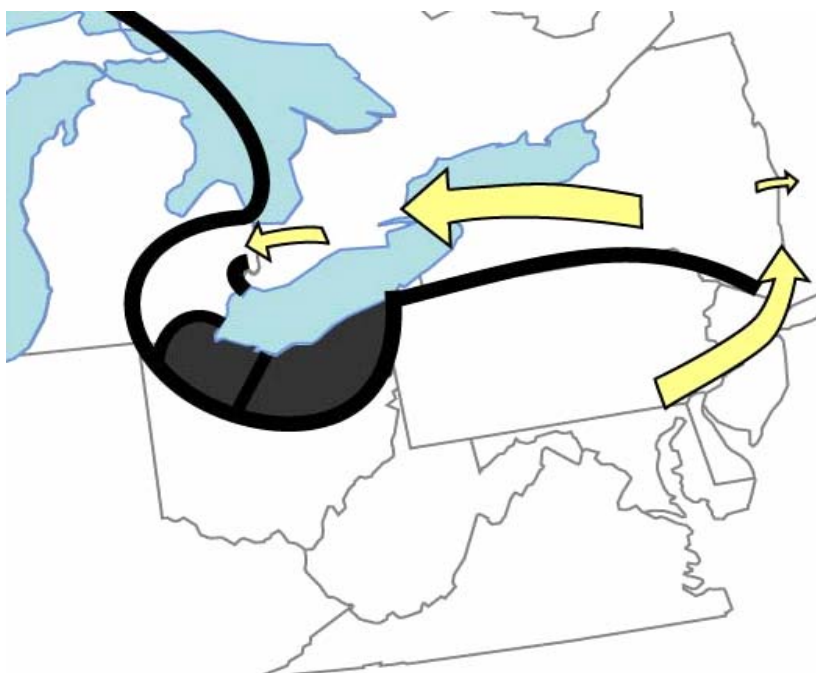
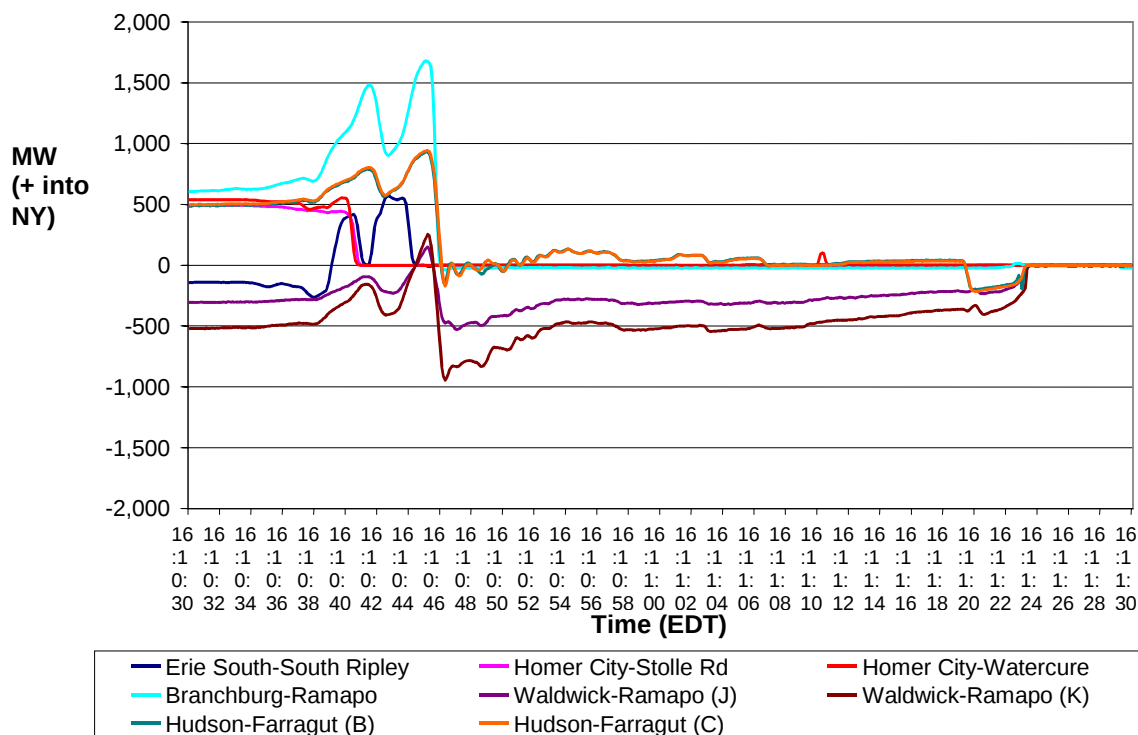


Figure IV.27 — Power Flows at 16:10:45

As shown in Figure IV.27, the 69-mile long Branchburg-Ramapo line and Ramapo transformer between New Jersey and New York was the last major transmission path remaining between the Eastern Interconnection and the area ultimately affected by the blackout. Figure IV.28 shows how that line disconnected at 16:10:45, along with other underlying 230 and 138-kV lines in northeastern New Jersey. Branchburg-Ramapo was carrying over 3,000 MVA and 4,500 amps with voltage at 79 percent before it tripped, either on a high-speed swing into zone 1 or on a direct transfer trip. The investigation team is still examining why the higher impedance 230-kV overhead lines tripped while the underground Hudson-Farragut 230-kV cables did not; the available data suggest that the lower impedance of underground cables made these less vulnerable to the electrical strain placed on the system.



This left the northeast portion of New Jersey connected to New York, while Pennsylvania and the rest of New Jersey remained connected to the rest of the Eastern Interconnection. Within northeastern New Jersey, the separation occurred along the 230-kV corridors, which are the main supply feeds into the northern New Jersey area (the two Roseland-Athenia circuits and the Linden-Bayway circuit). These circuits supply the large customer load in northern New Jersey and are a primary route for power transfers into New York City, so they are usually more highly loaded than other interfaces. These lines tripped west and south of the large customer loads in northeast New Jersey.

The separation of New York, Ontario, and New England from the rest of the Eastern Interconnection occurred due to natural breaks in the system and automatic relay operations, which performed exactly as designed. No human intervention occurred by any operators to affect this split. At this point, the Eastern Interconnection was divided into two major sections. To the north and east of the separation point lay New York City, northern New Jersey, New York state, New England, the Canadian Maritimes provinces, eastern Michigan, the majority of Ontario, and the Québec system.

The rest of the Eastern Interconnection, to the south and west of the separation boundary, was not seriously affected by the blackout. Approximately 3,700 MW of excess generation in the main portion of

the Eastern Interconnection that was on-line to export into the Northeast was now separated from the load it had been serving. This left the northeastern island with even less in-island generation on-line as it attempted to stabilize during the final phase of the cascade.

E. Electrical Islands Seek Equilibrium: 16:10:46 to 16:12 EDT

1. Overview

During the next three seconds, the islanded northern section of the Eastern Interconnection broke apart internally.

- New York-New England upstate transmission lines disconnected: 16:10:46 to 16:10:47
- New York transmission system split along Total East interface: 16:10:49
- The Ontario system just west of Niagara Falls and west of St. Lawrence separated from the western New York island: 16:10:50

Figure VI.29 illustrates the events of this phase.

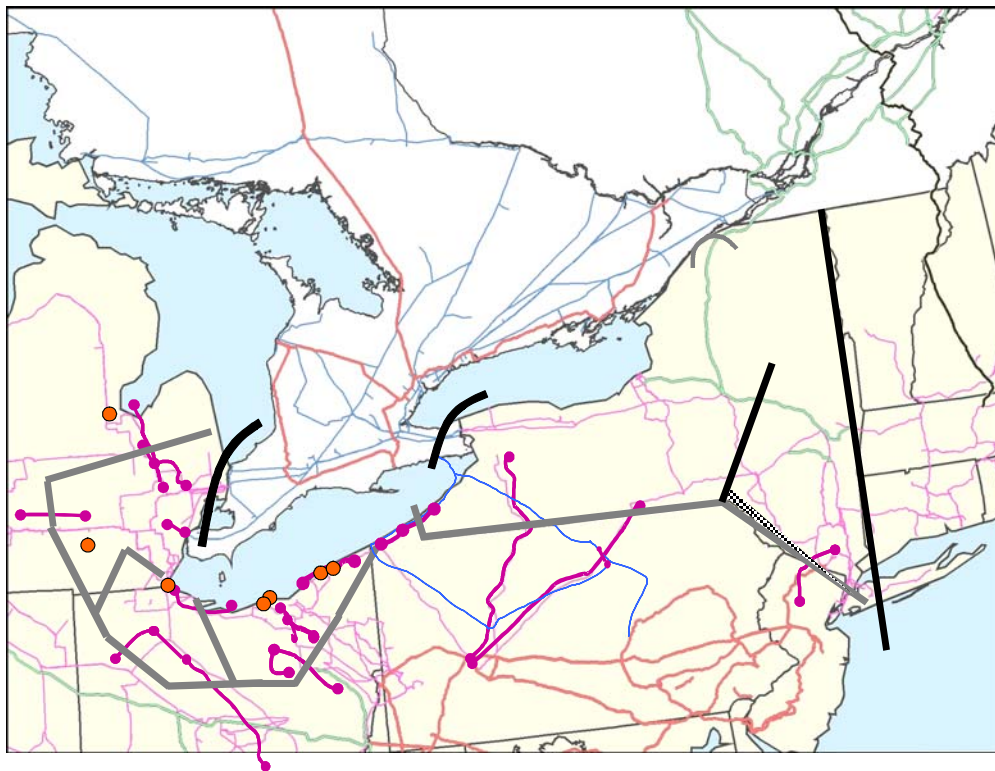


Figure IV.29 — New York and New England Separate, Multiple Islands Form

A half minute later, two more separations occur:

- Southwestern Connecticut separates from New York City: 16:11:22
- Remaining transmission lines between Ontario and eastern Michigan separate: 16:11:57

By this point, most portions of the affected area were blacked out. This last phase of the cascade is principally about the search for balance between loads and generation in the various islands that have formed. The primary mechanism for reaching that balance was underfrequency load shedding (UFLS).

The following UFLS operated on the afternoon of August 14:

- Ohio shed over 1,883 MW beginning at 16:10:39
- Michigan shed a total of 2,835 MW
- New York shed a total of 10,648 MW in several steps, beginning at 16:10:48
- PJM shed a total of 1,324 MW in three steps in northern New Jersey, beginning at 16:10:48
- New England shed a total of 1,098 MW

The entire northeastern system was experiencing large scale, dynamic oscillations during this period. Even if the UFLS and generation had been perfectly balanced at any moment in time, these oscillations would have made stabilization difficult and unlikely. Figure IV.30 gives an overview of the power flows and frequencies during the period 16:10:45 through 16:11:00, capturing most of the key events in the final phase of the cascade.

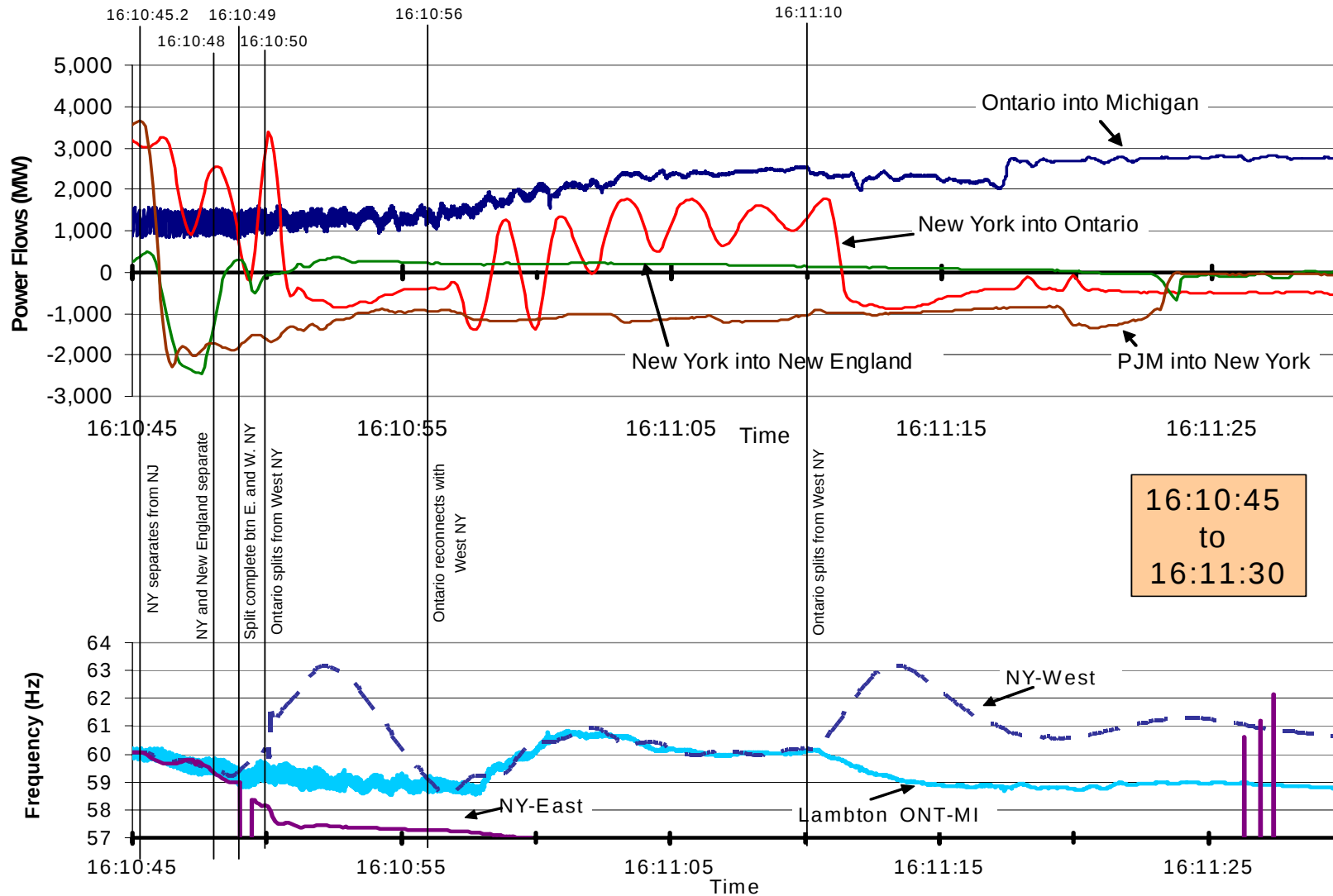


Figure IV.30 — Measured Power Flows and Frequency Across Regional Interfaces, 16:10:45 to 16:11:30, With Key Events in the Cascade

After the blackout of 1965, the utilities serving New York City and neighboring northern New Jersey increased the integration between the systems serving this area to increase the flow capability into New York and improve the reliability of the system as a whole. The combination of the facilities in place and the pattern of electrical loads and flows on August 14 caused New York to be tightly linked electrically to northern New Jersey and southwestern Connecticut, and moved previously existing weak spots on the grid out past this combined load and network area.

2. New York-New England Separation: 16:10:46 to 16:10:54 EDT

Prior to New England's separation from the Eastern Interconnection at approximately 16:11, voltages became depressed due to the large power swings occurring across the interconnection while trying to feed the collapsing areas to the west. Immediately following the separation of New England and the Maritimes from the Eastern Interconnection, the Connecticut transmission system voltages went high. This was the result of capacitors remaining in service, load loss, reduced reactive losses on transmission circuits, and loss of generation to regulate the system voltage. Overvoltage protective relays operated, tripping both transmission and distribution capacitors across the Connecticut system. In addition, the load in the area of Connecticut that was still energized began to increase during the first 7–10 minutes following the initial separation as loads reconnected. This increase in load was most likely due to customers restoring process load, which tripped during transient instability. The load increase combined with the capacitors tripping resulted in the transmission voltages going from high to low within approximately five minutes. To stabilize the system, New England operators ordered all fast start generation by 16:16 and took decisive action to manually drop approximately 80 MW of load in southwest Connecticut by 16:39. They dropped another 325 MW in Connecticut and 100 MW in western Massachusetts by 16:40. These measures helped to stabilize the New England and Maritime island following their separation from the rest of the Eastern Interconnection.

Between 16:10:46 and 16:10:54, the separation between New England and New York occurred along five northern ties and seven ties within southwestern Connecticut. At the time of the east-west separation in New York at 16:10:49, New England was isolated from the eastern New York island. The only remaining tie was the PV-20 circuit connecting New England and the western New York island, which tripped at 16:10:54. Because New England was exporting to New York before the disturbance across the southwestern Connecticut tie, but importing on the Norwalk-Northport tie, the Pleasant Valley path opened east of Long Mountain (in other words, internal to southwestern Connecticut) rather than along the actual New York-New England tie. Immediately before the separation, the power swing out of New England occurred because the New England generators had increased output in response to the drag of power through Ontario and New York into Michigan and Ohio. The power swings continuing through the region caused this separation and caused Vermont to lose approximately 70 MW of load.

When the ties between New York and New England disconnected, most of New England, along with the Maritime provinces of New Brunswick and Nova Scotia, became an island with generation and demand balanced sufficiently close that it was able to remain operational. The New England system had been exporting close to 600 MW to New York, so it was relatively generation-rich and experienced continuing fluctuations until it reached equilibrium. Before the Maritimes and New England separated from the Eastern Interconnection at approximately 16:11, voltages became depressed across portions of New England and some large customers disconnected themselves automatically. However, southwestern Connecticut separated from New England and remained tied to the New York system for about one minute.

While frequency within New England fluctuated slightly and recovered quickly after 16:10:40, frequency in the New York-Ontario-Michigan-Ohio island varied severely as additional lines, loads, and generators tripped, reflecting the magnitude of the generation deficiency in Michigan and Ohio.

Due to its geography and electrical characteristics, the Québec system in Canada is tied to the remainder of the Eastern Interconnection via high-voltage DC links instead of AC transmission lines. Québec was able to survive the power surges with only small impacts because the DC connections shielded it from the frequency swings. At the same time, the DC ties into upper New York and New England served as resources to stabilize those two islands and helped keep them energized during the cascade.

3. New York Transmission Split East-West: 16:10:49 EDT

The transmission system split internally within New York along the Total East interface, with the eastern portion islanding to contain New York City, northern New Jersey, and southwestern Connecticut. The eastern New York island had been importing energy, so it did not have enough surviving generation on-line to balance load. Frequency declined quickly to below 58.0 Hz and triggered 7,115 MW of automatic UFLS. Frequency declined further, as did voltage, causing pre-designed trips at the Indian Point nuclear plant and other generators in and around New York City through 16:11:10. New York's Total East and Central East interfaces, where the New York internal split occurred, are routinely among the most heavily loaded paths in the state and are operated under thermal, voltage, and stability limits to respect their relative vulnerability and importance.

Examination of the loads and generation in the eastern New York island indicates that before 16:10:00, the area had been importing electricity and had less generation on-line than load. At 16:10:50, seconds after the separation along the Total East interface, the eastern New York area had experienced significant load reductions due to UFLS — Consolidated Edison, which serves New York City and surrounding areas, dropped more than 40 percent of its load on automatic UFLS. But at this time, the system was still experiencing dynamic conditions; as illustrated in Figure IV.31, frequency was falling, flows and voltages were oscillating, and power plants were tripping off-line. Had there been a slow islanding situation and more generation on-line, it might have been possible for the Eastern New York island to rebalance given its high level of UFLS. However, events happened so quickly and the power swings were so large that rebalancing would have been unlikely, with or without the northern New Jersey and southwestern Connecticut loads hanging onto eastern New York. This was further complicated because the high rate of change in voltages at load buses reduced the actual levels of load shed by UFLS relative to the levels needed and expected.

4. Western New York-Ontario Interface

The Ontario system separated from the western New York island just west of Niagara Falls and west of St. Lawrence at 16:10:50. This separation was due to relay operations that disconnected nine 230-kV lines within Ontario. These left most of Ontario isolated. Ontario's large Beck and Saunders hydro stations, along with some Ontario load, the NYPA Niagara and St. Lawrence hydro stations, and NYPA's 765-kV AC interconnection to their HVDC tie with Québec, remained connected to the western New York system, supporting the demand in upstate New York. From 16:10:49 to 16:10:50, frequency in Ontario declined below 59.3 Hz, initiating automatic UFLS (3,000 MW). This load shedding dropped about 12 percent of Ontario's remaining load. Between 16:10:50 and 16:10:56, the isolation of Ontario's 2,300 MW Beck and Saunders hydro units onto the western New York island, coupled with UFLS, caused the frequency in this island to rise to 63.4 Hz due to excess generation relative to the load remaining within the island. This is shown in Figure VI.31. The high frequency caused trips of five of the U.S. nuclear units within the island, and the last one tripped on the second frequency rise.

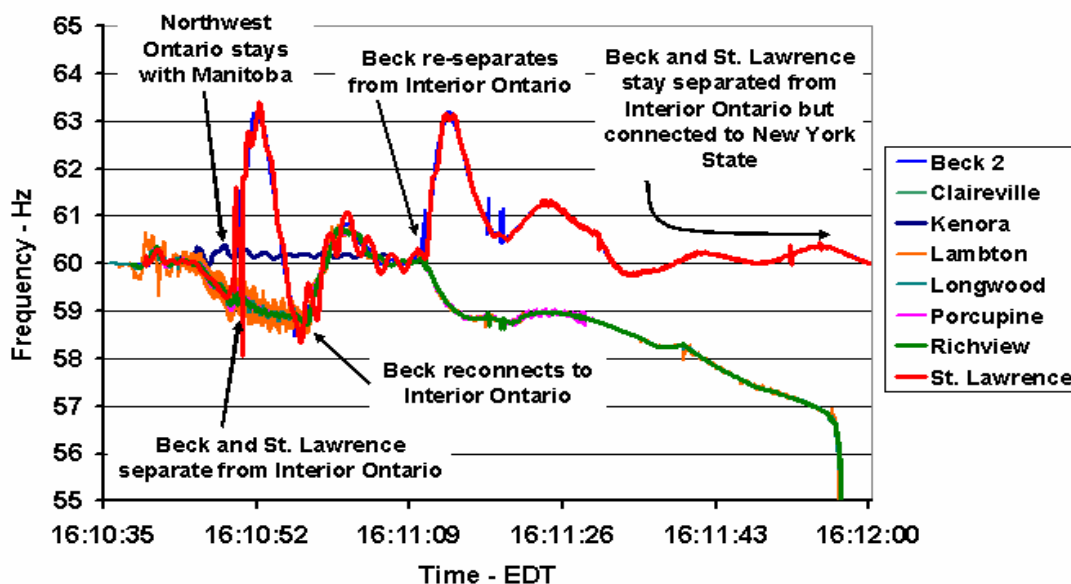


Figure IV.31 — Separation of Ontario and Western New York

Three of the 230-kV transmission circuits reclosed near Niagara automatically to reconnect Ontario to New York at 16:10:56. Even with these lines reconnected, the main Ontario island (still attached to New York and eastern Michigan) was extremely deficient in generation, so its frequency declined towards 58.8 Hz, the threshold for the second stage of UFLS. Over the next two seconds, another 19 percent of Ontario demand (4,800 MW) automatically disconnected by UFLS. At 16:11:10, these same three lines tripped a second time west of Niagara, and New York and most of Ontario separated for a final time. Following this separation, the frequency in Ontario declined to 56 Hz by 16:11:57. With Ontario still supplying 2,500 MW to the Michigan-Ohio load pocket, the remaining ties with Michigan tripped at 16:11:57. Ontario system frequency declined, leading to a widespread shutdown at 16:11:58 and a loss of 22,500 MW of load in Ontario, including the cities of Toronto, Hamilton, and Ottawa.

5. Southwest Connecticut Separated From New York City: 16:11:22 EDT

In southwestern Connecticut, when the Long Mountain-Plum Tree line (connected to the Pleasant Valley substation in New York) disconnected at 16:11:22, it left about 500 MW of demand supplied only through a 138-kV underwater tie to Long Island. About two seconds later, the two 345-kV circuits connecting southeastern New York to Long Island tripped, isolating Long Island and southwestern Connecticut, which remained tied together by the underwater Norwalk Harbor to Northport 138-kV cable. The cable tripped about 20 seconds later, causing southwestern Connecticut to black out.

6. Western New York Stabilizes

Within the western New York island, the 345-kV system remained intact from Niagara east to the Utica area, and from the St. Lawrence/Plattsburgh area south to the Utica area through both the 765-kV and 230-kV circuits. Ontario's Beck and Saunders generation remained connected to New York at Niagara and St. Lawrence, respectively, and this island stabilized with about 50 percent of the pre-event load remaining. The boundary of this island moved southeastward as a result of the reclosure of Fraser-to-Coopers Corners 345-kV at 16:11:23.

7. Eastern New York Island Splits

As a result of the severe frequency and voltage changes, many large generating units in New York and Ontario tripped off-line. The eastern island of New York, including the heavily populated areas of southeastern New York, New York City, and Long Island, experienced severe frequency and voltage decline. At 16:11:29, the New Scotland-to-Leeds 345-kV circuits tripped, separating the eastern New York island into northern and southern sections. The small remaining load in the northern portion of the eastern island (the Albany area) retained electric service, supplied by local generation until it could be resynchronized with the western New York island. The southern island, including New York City, rapidly collapsed into a blackout.

8. Remaining Transmission Lines Between Ontario and Eastern Michigan Separate: 16:11:57 EDT

Before the blackout, New England, New York, Ontario, eastern Michigan, and northern Ohio were scheduled net importers of power. When the western and southern lines serving Cleveland, Toledo, and Detroit collapsed, most of the load remained on those systems, but some generation had tripped. This exacerbated the generation/load imbalance in areas that were already importing power. The power to serve this load came through the only major path available, via Ontario. After most of IMO was separated from New York and generation to the north and east, much of the Ontario load and generation was lost; it took only moments for the transmission paths west from Ontario to Michigan to fail.

When the cascade was over at about 16:12, much of the disturbed area was completely blacked out, but isolated pockets still had service because load and generation had reached equilibrium. Ontario's large Beck and Saunders hydro stations, along with some Ontario load, the NYPA Niagara and St. Lawrence hydro stations, and NYPA's 765-kV AC interconnection to the Québec HVDC tie, remained connected to the western New York system, supporting demand in upstate New York.

Figure IV.32 shows frequency data collected by the distribution-level monitors of Softswitching Technologies, Inc. (a commercial power quality company serving industrial customers) for the area affected by the blackout. The data reveal at least five separate electrical islands in the Northeast as the cascade progressed. The two paths of red circles on the frequency scale reflect the Albany area island (upper path) versus the New York City island, which declined and blacked out much earlier.

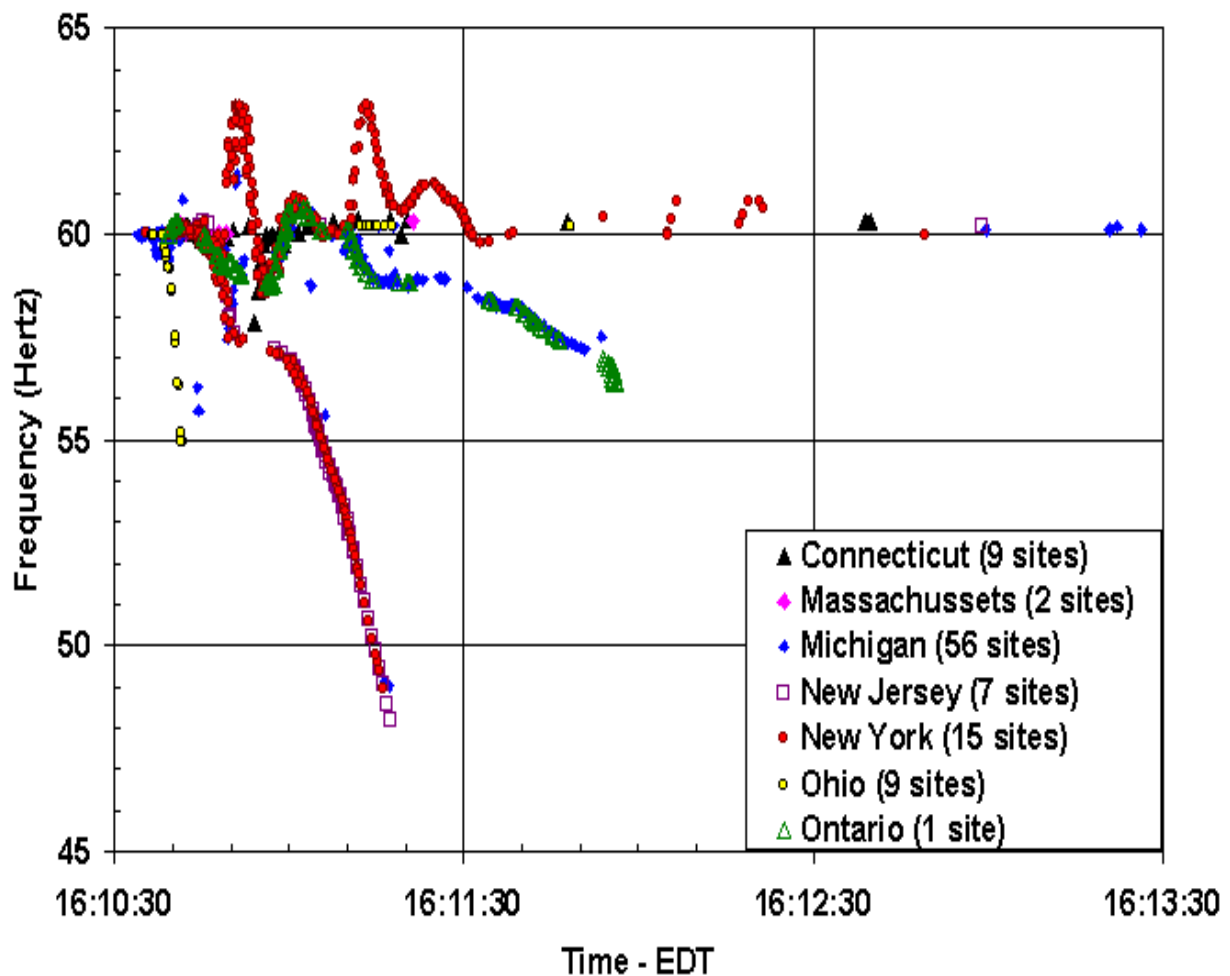


Figure IV.32 — Electric Islands Reflected in Frequency Plot

9. Cascading Sequence Essentially Complete: 16:13 EDT

Most of the Northeast (the area shown in gray in Figure VI.33) had now blacked out. Some isolated areas of generation and load remained on-line for several minutes. Some of those areas in which a close generation-demand balance could be maintained remained operational.

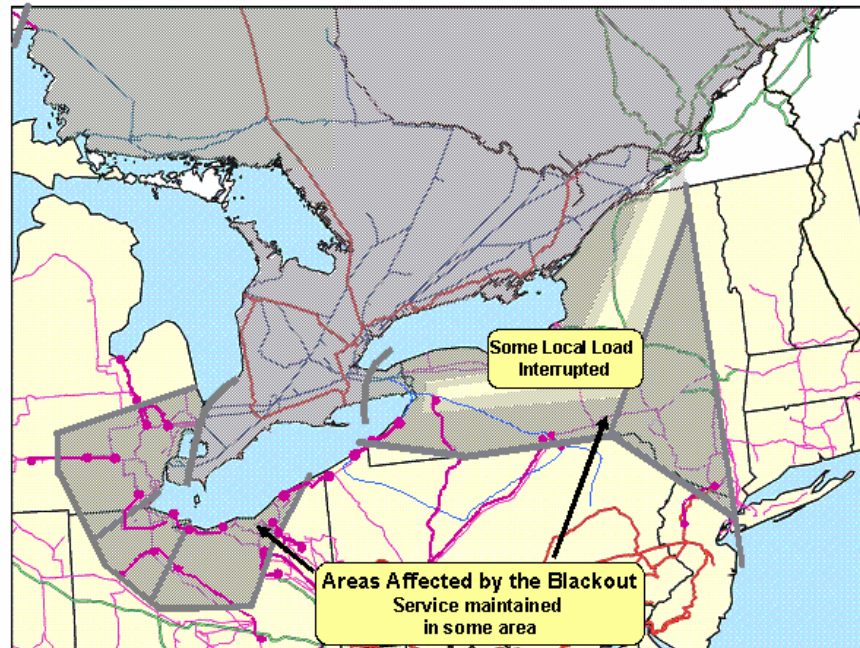


Figure IV.33 — Areas Affected by the Blackout

One relatively large island remained in operation, serving about 5,700 MW of demand, mostly in western New York. Ontario's large Beck and Saunders hydro stations, along with some Ontario load, the NYPA Niagara and St. Lawrence hydro stations, and NYPA's 765-kV AC interconnection with Québec, remained connected to the western New York system, supporting demand in upstate New York. This island formed the basis for restoration in both New York and Ontario.

The entire cascade sequence is summarized graphically in figure VI.34.

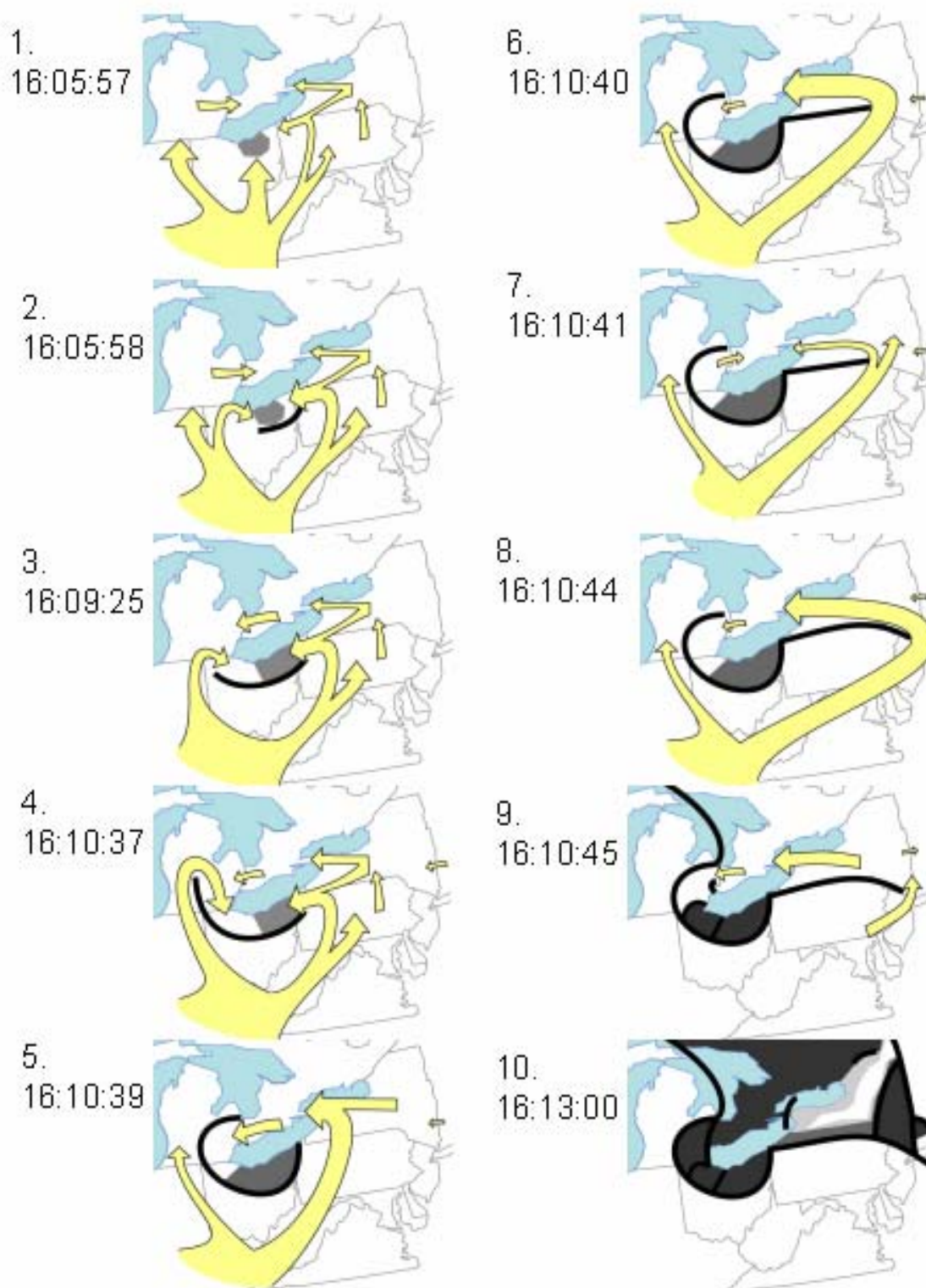


Figure IV.34 — Cascade Sequence Summary

V. Conclusions and Recommendations

A. General Conclusions

The August 14 blackout had many similarities with previous large-scale blackouts, including the 1965 Northeast blackout that was the basis for forming NERC in 1968, and the July 1996 outages in the West. Common factors include: conductor contacts with trees, inability of system operators to visualize events on the system, failure to operate within known safe limits, ineffective operational communications and coordination, inadequate training of operators to recognize and respond to system emergencies, and inadequate reactive power resources.

The general conclusions of the NERC investigation are as follows:

- Several entities violated NERC operating policies and planning standards, and those violations contributed directly to the start of the cascading blackout.
- The approach used to monitor and ensure compliance with NERC and regional reliability standards was inadequate to identify and resolve specific compliance violations before those violations led to a cascading blackout.
- Reliability coordinators and control areas have adopted differing interpretations of the functions, responsibilities, authorities, and capabilities needed to operate a reliable power system.
- In some regions, data used to model loads and generators were inaccurate due to a lack of verification through benchmarking with actual system data and field testing.
- Planning studies, design assumptions, and facilities ratings were not consistently shared and were not subject to adequate peer review among operating entities and regions.
- Available system protection technologies were not consistently applied to optimize the ability to slow or stop an uncontrolled cascading failure of the power system.
- Deficiencies identified in studies of prior large-scale blackouts were repeated, including poor vegetation management, operator training practices, and a lack of adequate tools that allow operators to visualize system conditions.

B. Causal Analysis Results

This section summarizes the causes of the blackout. Investigators found that the Sammis-Star 345-kV line trip was a seminal event, after which power system failures began to spread beyond northeastern Ohio to affect other areas. After the Sammis-Star line outage at 16:05:57, the accelerating cascade of line and generator outages would have been difficult or impossible to stop with installed protection and controls. Therefore, the causes of the blackout are focused on problems that occurred before the Sammis-Star outage.

The causes of the blackout described here did not result from inanimate events, such as “the alarm processor failed” or “a tree contacted a power line.” Rather, the causes of the blackout were rooted in deficiencies resulting from decisions, actions, and the failure to act of the individuals, groups, and organizations involved. These causes were preventable prior to August 14 and are correctable. Simply put — blaming a tree for contacting a line serves no useful purpose. The responsibility lies with the organizations and persons charged with establishing and implementing an effective vegetation management program to maintain safe clearances between vegetation and energized conductors.

Each cause identified here was verified to have existed on August 14 prior to the blackout. Each cause was also determined to be both a necessary condition to the blackout occurring and, in conjunction with the other causes, sufficient to cause the blackout. In other words, each cause was a direct link in the causal chain leading to the blackout and the absence of any one of these causes could have broken that chain and prevented the blackout. This definition distinguishes causes as a subset of a broader category of identified deficiencies. Other deficiencies are noted in the next section; they may have been contributing factors leading to the blackout or may present serious reliability concerns completely unrelated to the blackout, but they were not deemed by the investigators to be direct causes of the blackout. They are still important; however, because they might have caused a blackout under a different set of circumstances.

1. Causes of the Blackout

Group 1 Causes: FE lacked situational awareness of line outages and degraded conditions on the FE system. The first five causes listed below collectively resulted in a lack of awareness by the FE system operators that line outages were occurring on the FE system and that operating limit violations existed after the trip of the Chamberlin-Harding line at 15:05 and worsened with subsequent line trips. This lack of situational awareness precluded the FE system operators from taking corrective actions to return the system to within limits, and from notifying MISO and neighboring systems of the degraded system conditions and loss of critical functionality in the control center.

Cause 1a: FE had no alarm failure detection system. Although the FE alarm processor stopped functioning properly at 14:14, the computer support staff remained unaware of this failure until the second EMS server failed at 14:54, some 40 minutes later. Even at 14:54, the responding support staff understood only that all of the functions normally hosted by server H4 had failed, and did not realize that the alarm processor had failed 40 minutes earlier. Because FE had no periodic diagnostics to evaluate and report the state of the alarm processor, nothing about the eventual failure of two EMS servers would have directly alerted the support staff that the alarms had failed in an infinite loop lockup — or that the alarm processor had failed in this manner both earlier and independently of the server failure events. Even if the FE computer support staff had communicated the EMS failure to the operators (which they did not) and fully tested the critical functions after restoring the EMS (which they did not), there still would have been a minimum of 40 minutes, from 14:14 to 14:54, during which the support staff was unaware of the alarm processor failure.

Cause 1b: FE computer support staff did not effectively communicate the loss of alarm functionality to the FE system operators after the alarm processor failed at 14:14, nor did they have a formal procedure to do so. Knowing the alarm processor had failed would have provided FE operators the opportunity to detect the Chamberlin-Harding line outage shortly after 15:05 using supervisory displays still available in their energy management system. Knowledge of the Chamberlin-Harding line outage would have enabled FE operators to recognize worsening conditions on the FE system and to consider manually reclosing the Chamberlin-Harding line as an emergency action after subsequent outages of the Hanna-Juniper and Star-South Canton 345-kV lines. Knowledge of the alarm processor failure would have allowed the FE operators to be more receptive to information being received from MISO and neighboring systems regarding degrading conditions on the FE system. This knowledge would also have allowed FE operators to warn MISO and neighboring systems of the loss of a critical monitoring function in the FE control center computers, putting them on alert to more closely monitor conditions on the FE system, although there is not a specific procedure requiring FE to warn MISO of a loss of a critical control center function. The FE operators were complicit in this deficiency by not recognizing the alarm processor failure existed, although no new alarms were received by the operators after 14:14. A period of more than 90

minutes elapsed before the operators began to suspect a loss of the alarm processor, a period in which, on a typical day, scores of routine alarms would be expected to print to the alarm logger.

Cause 1c: FE control center computer support staff did not fully test the functionality of applications, including the alarm processor, after a server failover and restore. After the FE computer support staff conducted a warm reboot of the energy management system to get the failed servers operating again, they did not conduct a sufficiently rigorous test of critical energy management system applications to determine that the alarm processor failure still existed. Full testing of all critical energy management functions after restoring the servers would have detected the alarm processor failure as early as 15:08 and would have cued the FE system operators to use an alternate means to monitor system conditions. Knowledge that the alarm processor was still failed after the server was restored would have enabled FE operators to proactively monitor system conditions, become aware of the line outages occurring on the system, and act on operational information that was received. Knowledge of the alarm processor failure would also have allowed FE operators to warn MISO and neighboring systems, assuming there was a procedure to do so, of the loss of a critical monitoring function in the FE control center computers, putting them on alert to more closely monitor conditions on the FE system.

Cause 1d: FE operators did not have an effective alternative to easily visualize the overall conditions of the system once the alarm processor failed. An alternative means of readily visualizing overall system conditions, including the status of critical facilities, would have enabled FE operators to become aware of forced line outages in a timely manner even though the alarms were non-functional. Typically, a dynamic map board or other type of display could provide a system status overview for quick and easy recognition by the operators. As with the prior causes, this deficiency precluded FE operators from detecting the degrading system conditions, taking corrective actions, and alerting MISO and neighboring systems.

Cause 1e: FE did not have an effective contingency analysis capability cycling periodically on-line and did not have a practice of running contingency analysis manually as an effective alternative for identifying contingency limit violations. Real-time contingency analysis, cycling automatically every 5–15 minutes, would have alerted the FE operators to degraded system conditions following the loss of the Eastlake 5 generating unit and the Chamberlin-Harding 345-kV line. Initiating a manual contingency analysis after the trip of the Chamberlin-Harding line could also have identified the degraded system conditions for the FE operators. Knowledge of a contingency limit violation after the loss of Chamberlin-Harding and knowledge that conditions continued to worsen with the subsequent line losses would have allowed the FE operators to take corrective actions and notify MISO and neighboring systems of the developing system emergency. FE was operating after the trip of the Chamberlin-Harding 345-kV line at 15:05, such that the loss of the Perry 1 nuclear unit would have caused one or more lines to exceed their emergency ratings.

Group 2 Cause: FE did not effectively manage vegetation in its transmission rights-of-way.

Cause 2: FE did not effectively manage vegetation in its transmission line rights-of-way. The lack of situational awareness resulting from Causes 1a–1e would have allowed a number of system failure modes to go undetected. However, it was the fact that FE allowed trees growing in its 345-kV transmission rights-of-way to encroach within the minimum safe clearances from energized conductors that caused the Chamberlin-Harding, Hanna-Juniper, and Star-South Canton 345-kV line outages. These three tree-related outages triggered the localized cascade of the Cleveland-Akron 138-kV system and the overloading and tripping of the Sammis-Star line, eventually snowballing into an uncontrolled wide-area cascade. These three lines experienced non-random, common mode failures due to unchecked tree growth. With properly cleared rights-of-way and calm weather, such

as existed in Ohio on August 14, the chances of those three lines randomly tripping within 30 minutes is extremely small. Effective vegetation management practices would have avoided this particular sequence of line outages that triggered the blackout. However, effective vegetation management might not have precluded other latent failure modes. For example, investigators determined that there was an elevated risk of a voltage collapse in the Cleveland-Akron area on August 14 if the Perry 1 nuclear plant had tripped that afternoon in addition to Eastlake 5, because the transmission system in the Cleveland-Akron area was being operated with low bus voltages and insufficient reactive power margins to remain stable following the loss of Perry 1.

Group 3 Causes: Reliability coordinators did not provide effective diagnostic support.

Cause 3a: MISO was using non-real-time information to monitor real-time operations in its area of responsibility. MISO was using its Flowgate Monitoring Tool (FMT) as an alternative method of observing the real-time status of critical facilities within its area of responsibility. However, the FMT was receiving information on facility outages from the NERC SDX, which is not intended as a real-time information system and is not required to be updated in real-time. Therefore, without real-time outage information, the MISO FMT was unable to accurately estimate real-time conditions within the MISO area of responsibility. If the FMT had received accurate line outage distribution factors representing current system topology, it would have identified a contingency overload on the Star-Juniper 345-kV line for the loss of the Hanna-Juniper 345-kV line as early as 15:10. This information would have enabled MISO to alert FE operators regarding the contingency violation and would have allowed corrective actions by FE and MISO. The reliance on non-real-time facility status information from the NERC SDX is not limited to MISO; others in the Eastern Interconnection use the same SDX information to calculate TLR curtailments in the IDC and make operational decisions on that basis. What was unique compared to other reliability coordinators on that day was MISO's reliance on the SDX for what they intended to be a real-time system monitoring tool.

Cause 3b: MISO did not have real-time topology information for critical lines mapped into its state estimator. The MISO state estimator and network analysis tools were still considered to be in development on August 14 and were not fully capable of automatically recognizing changes in the configuration of the modeled system. Following the trip of lines in the Cinergy system at 12:12 and the DP&L Stuart-Atlanta line at 14:02, the MISO state estimator failed to solve correctly as a result of large numerical mismatches. MISO real-time contingency analysis, which operates only if the state estimator solves, did not operate properly in automatic mode again until after the blackout. Without real-time contingency analysis information, the MISO operators did not detect that the FE system was in a contingency violation after the Chamberlin-Harding 345-kV line tripped at 15:05. Since MISO was not aware of the contingency violation, MISO did not inform FE and thus FE's lack of situational awareness described in Causes 1a-e was allowed to continue. With an operational state estimator and real-time contingency analysis, MISO operators would have known of the contingency violation and could have informed FE, thus enabling FE and MISO to take timely actions to return the system to within limits.

Cause 3c: The PJM and MISO reliability coordinators lacked an effective procedure on when and how to coordinate an operating limit violation observed by one of them in the other's area due to a contingency near their common boundary. The lack of such a procedure caused ineffective communications between PJM and MISO regarding PJM's awareness of a possible overload on the Sammis-Star line as early as 15:48. An effective procedure would have enabled PJM to more clearly communicate the information it had regarding limit violations on the FE system, and would have enabled MISO to be aware of those conditions and initiate corrective actions with FE.

C. Other Deficiencies

The deficiencies listed above were determined by investigators to be necessary and sufficient to cause the August 14 blackout — therefore they are labeled causes. Investigators identified many other deficiencies, which did not meet the “necessary and sufficient” test, and therefore were not labeled as causes of the blackout. In other words, a sufficient set of deficiencies already existed to cause the blackout without these other deficiencies.

However, these other deficiencies represent significant conclusions of the investigation, as many of them aggravated the enabling conditions or the severity of the consequences of the blackout. An example is the ninth deficiency listed below, regarding poor communications within the FE control center. Poor communications within the control center did not cause the blackout and the absence of those poor communications within the FE control center would not have prevented the blackout. However, poor communications in the control center was a contributing factor, because it increased the state of confusion in the control center and exacerbated the FE operators’ lack of situational awareness. The investigators also discovered a few of these deficiencies to be unrelated to the blackout but still of significant concern to system reliability. An example is deficiency number eight: FE was operating close to a voltage collapse in the Cleveland-Akron area, although voltage collapse did not initiate the sequence of events that led to the blackout.

1. Summary of Other Deficiencies Identified in the Blackout Investigation

1. **The NERC and ECAR compliance programs did not identify and resolve specific compliance violations before those violations led to a cascading blackout.** Several entities in the ECAR region violated NERC operating policies and planning standards, and those violations contributed directly to the start of the cascading blackout. Had those violations not occurred, the blackout would not have occurred. The approach used for monitoring and assuring compliance with NERC and regional reliability standards prior to August 14 delegated much of the responsibility and accountability to the regional level. Due to confidentiality considerations, NERC did not receive detailed information about violations of specific parties prior to August 14. This approach meant that the NERC compliance program was only as effective as that of the weakest regional reliability council.
2. **There are no commonly accepted criteria that specifically address safe clearances of vegetation from energized conductors.** The National Electrical Safety Code specifies in detail criteria for clearances from several classes of obstructions, including grounded objects. However, criteria for vegetation clearances vary by state and province, and by individual utility.
3. **Problems identified in studies of prior large-scale blackouts were repeated on August 14, including deficiencies in vegetation management, operator training, and tools to help operators better visualize system conditions.** Although these issues had been previously reported, NERC and some regions did not have a systematic approach to tracking successful implementation of those prior recommendations.
4. **Reliability coordinators and control areas have adopted differing interpretations of the functions, responsibilities, authorities, and capabilities needed to operate a reliable power system.** For example, MISO delegated substantial portions of its reliability oversight functions to its member control areas and did not provide a redundant set of eyes adequate for monitoring a wide-area view of reliability in its area of responsibility. Further, NERC operating policies do not specify what tools are specifically required of control areas and reliability coordinators, such as state estimation and network analysis tools, although the policies do specify the expected outcomes of analysis.

5. **In ECAR, data used to model loads and generators were inaccurate due to a lack of verification through benchmarking with actual system data and field testing.** Inaccuracies in load models and other system modeling data frustrated investigators trying to develop accurate simulations of the events on August 14. Inaccurate model data introduces potential errors in planning and operating models. Further, the lack of synchronized data recorders made the reconstruction of the sequence of events very difficult.
6. **In ECAR, planning studies, design assumptions, and facilities ratings were not consistently shared and were not subject to adequate peer review among operating entities and regions.** As a result, systems were studied and analyzed in “silos” and study assumptions and results were not always understood by neighboring systems, although those assumptions affected those other systems.
7. **Available system protection technologies were not consistently applied to optimize the ability to slow or stop an uncontrolled cascading failure of the power system.** The effects of zone 3 relays, the lack of under-voltage load shedding, and the coordination of underfrequency load shedding and generator protection are all areas requiring further investigation to determine if opportunities exist to limit or slow the spread of a cascading failure of the system.
8. **FE was operating its system with voltages below critical voltages and with inadequate reactive reserve margins.** FE did not retain and apply knowledge from earlier system studies concerning voltage collapse concerns in the Cleveland-Akron area. Conventional voltage studies done by FE to assess normal and abnormal voltage ranges and percent voltage decline did not accurately determine an adequate margin between post-contingency voltage and the voltage collapse threshold at various locations in their system. If FE had conducted voltage stability analyses using well-established P-V and Q-V techniques, FE would have detected insufficient dynamic reactive reserves at various locations in their system for the August 14 operating scenario that includes the Eastlake 5 outage. Additionally, FE’s stated acceptable ranges for voltage are not compatible with neighboring systems or interconnected systems in general. FE was operating in apparent violation of its own historical planning and operating criteria that were developed and used by Centerior Energy Corporation (The Cleveland Electric Illuminating Company and the Toledo Edison Company) prior to 1998 to meet the relevant NERC and ECAR standards and criteria. In 1999, FE reduced its operating voltage lower limits in the Cleveland-Akron area compared to those criteria used in prior years. These reduced minimum operating voltage limits were disclosed in FE’s 1999–2003 Planning & Operating Criteria Form 715 submittal to FERC, but were not challenged at the time.
9. **FE did not have an effective protocol for sharing operator information within the control room and with others outside the control room.** FE did not have an effective plan for communications in the control center during a system emergency. Communications within the control center and with others outside the control center were confusing and hectic. The communications were not effective in helping the operators focus on the most urgent problem in front of them — the emerging system and computer failures.
10. **FE did not have an effective generation redispatch plan and did not have sufficient redispatch resources to relieve overloaded transmission lines supplying northeastern Ohio.** Following the loss of the Chamberlin-Harding 345-kV line, FE had a contingency limit violation but did not have resources available for redispatch to effectively reduce the contingency overload within 30 minutes.
11. **FE did not have an effective load reduction plan and did not have an adequate load reduction capability, whether automatic or manual, to relieve overloaded transmission lines**

supplying northeastern Ohio. A system operator is required to have adequate resources to restore the system to a secure condition within 30 minutes or less of a contingency. Analysis shows that shedding 2,000 MW of load in the Cleveland-Akron area after the loss of the Star-South Canton 345-kV line or shedding 2,500 after the West Akron Substation 138-kV bus failure could have halted the cascade in the northeastern Ohio area.

- 12. FE did not adequately train its operators to recognize and respond to system emergencies, such as multiple contingencies.** The FE operators did not recognize the information they were receiving as clear indications of an emerging system emergency. Even when the operators grasped the idea that their computer systems had failed and the system was in trouble, the operators did not formally declare a system emergency and inform MISO and neighboring systems.
- 13. FE did not have the ability to transfer control of its power system to an alternate center or authority during system emergencies.** FE had not arranged for a backup control center or backup system control and monitoring functions. A typical criterion would include the need to evacuate the control center due to fire or natural disaster. Although control center evacuation was not required on August 14, FE had an equivalent situation with the loss of its critical monitoring and control functionality in the control center.
- 14. FE operational planning and system planning studies were not sufficiently comprehensive to ensure reliability because they did not include a full range of sensitivity studies based on the 2003 Summer Base Case.** A comprehensive range of planning studies would have involved analyses of all operating scenarios likely to be encountered, including those for unusual operating conditions and potential disturbance scenarios.
- 15. FE did not perform adequate hour-ahead operations planning studies after Eastlake 5 tripped off-line at 13:31 to ensure that FE could maintain a 30-minute response capability for the next contingency.** The FE system was not within single contingency limits from 15:06 to 16:06. In addition to day-ahead planning, the system should have been restudied after the forced outage of Eastlake 5.
- 16. FE did not perform adequate day-ahead operations planning studies to ensure that FE had adequate resources to return the system to within contingency limits following the possible loss of their largest unit, Perry 1.** After Eastlake 4 was forced out on August 13, the operational plan was not modified for the possible loss of the largest generating unit, Perry 1.
- 17. FE did not have or use specific criteria for declaring a system emergency.**
- 18. ECAR and MISO did not precisely define “critical facilities” such that the 345-kV lines in FE that caused a major cascading failure would have to be identified as critical facilities for MISO.** MISO’s procedure in effect on August 14 was to request FE to identify critical facilities on its system to MISO.
- 19. MISO did not have additional monitoring tools that provided high-level visualization of the system.** A high-level monitoring tool, such as a dynamic map board, would have enabled MISO operators to view degrading conditions in the FE system.
- 20. ECAR and its member companies did not adequately follow ECAR Document 1 to conduct regional and interregional system planning studies and assessments.** This would have

enabled FE to further develop specific operating limits of their critical interfaces by assessing the effects of power imports and exports, and regional and interregional power transfers.

21. **ECAR did not have a coordinated procedure to develop and periodically review reactive power margins.** This would have enabled all member companies to establish maximum power transfer levels and minimum operating voltages to respect these reactive margins.
22. **Operating entities and reliability coordinators demonstrated an over-reliance on the administrative levels of the TLR procedure to remove contingency and actual overloads, when emergency redispatch of other emergency actions were necessary.** TLR is a market-based congestion relief procedure and is not intended for removing an actual violation in real-time.
23. **Numerous control areas in the Eastern Interconnection, including FE, were not correctly tagging dynamic schedules, resulting in large mismatches between actual, scheduled, and tagged interchange on August 14.** This prevented reliability coordinators in the Eastern Interconnection from predicting and modeling the effects of these transactions on the grid.

D. Blackout Recommendations

1. NERC Recommendations Approved February 10, 2004

On February 10, 2004, the NERC Board of Trustees approved 14 recommendations offered by the NERC Steering Group to address the causes of the August 14 blackout and other deficiencies. These recommendations remain valid and applicable to the conclusions of this final report. The recommendations fall into three categories:

Actions to Remedy Specific Deficiencies: Specific actions directed to FE, MISO, and PJM to correct the deficiencies that led to the blackout.

- Correct the direct causes of the August 14, 2003, blackout.

Strategic Initiatives: Strategic initiatives by NERC and the regional reliability councils to strengthen compliance with existing standards and to formally track completion of recommended actions from August 14, and other significant power system events.

- Strengthen the NERC Compliance Enforcement Program.
- Initiate control area and reliability coordinator reliability readiness audits.
- Evaluate vegetation management procedures and results.
- Establish a program to track implementation of recommendations.

Technical Initiatives: Technical initiatives to prevent or mitigate the impacts of future cascading blackouts.

- Improve operator and reliability coordinator training.
- Evaluate reactive power and voltage control practices.
- Improve system protection to slow or limit the spread of future cascading outages.

- Clarify reliability coordinator and control area functions, responsibilities, capabilities, and authorities.
- Establish guidelines for real-time operating tools.
- Evaluate lessons learned during system restoration.
- Install additional time-synchronized recording devices as needed.
- Reevaluate system design, planning, and operating criteria.
- Improve system modeling data and data exchange practices.

2. U.S.-Canada Power System Outage Task Force Recommendations

On April 5, 2004, the U.S.-Canada Power System Outage Task Force issued its final report of the August 14 blackout containing its 46 recommendations. The recommendations were grouped into four areas:

Group 1: Institutional Issues Related to Reliability (Recommendations 1–14)

Group 2: Support and Strengthen NERC's Actions of February 10, 2004 (Recommendations 15–31)

Group 3: Physical and Cyber Security of North American Bulk Power Systems (Recommendations 32–44)

Group 4: Canadian Nuclear Power Sector (Recommendations 45–46)

The investigation team is encouraged by the recommendations of the Task Force and believes these recommendations are consistent with the conclusions of the NERC investigation. Although the NERC investigation has focused on a technical analysis of the blackout, the policy recommendations in Group 1 appear to support many of NERC's findings regarding the need for legislation for enforcement of mandatory reliability standards. In other recommendations, the Task Force seeks to strengthen compliance enforcement and other NERC functions by advancing reliability policies at the federal, state, and provincial levels.

The second group of Task Force recommendations builds upon the original fourteen NERC recommendations approved in February 2004. NERC has considered these expanded recommendations, is implementing these recommendations where appropriate, and will inform the Task Force if additional considerations make any recommendation inappropriate or impractical.

The third group of Task Force recommendations addresses critical infrastructure protection issues. NERC agrees with the conclusions of the Task Force (Final Task Force report, page 132) that there is "no evidence that a malicious cyber attack was a direct or indirect cause of the August 14, 2003, power outage." The recommendations of the Task Force report are forward-looking and address issues that should be considered, whether or not there had been a blackout on August 14. NERC has assigned its Critical Infrastructure Protection Committee to evaluate these recommendations and report what actions, if any, NERC should take to implement those recommendations.

The fourth group of recommendations is specific to Canadian nuclear facilities and is outside the scope of NERC responsibilities.

Additional NERC Recommendations

While the ongoing NERC investigation has confirmed the validity of the original fourteen NERC recommendations and the NERC Steering Group concurs with the Task Force's recommendations, four

additional NERC recommendations resulted from further investigation since February and in consideration of the Task Force final report. The additional NERC recommendations are as follows:

Recommendation 4d — Develop a standard on vegetation clearances.

The Planning Committee, working with the Standards Authorization Committee, shall develop a measurable standard that specifies the minimum clearances between energized high voltage lines and vegetation. Appropriate criteria from the National Electrical Safety Code, or other appropriate code, should be adapted and interpreted so as to be applicable to vegetation.

Recommendation 15 — Develop a standing capability for NERC to investigate future blackouts and disturbances.

NERC shall develop and be prepared to implement a NERC standing procedure for investigating future blackouts and system disturbances. Many of the methods, tools, and lessons from the investigation of the August 14 blackout are appropriate for adoption.

Recommendation 16 — Accelerate the standards transition.

NERC shall accelerate the transition from existing operating policies, planning standards, and compliance templates to a clear and measurable set of reliability standards. (This recommendation is consistent with the Task Force recommendation 25.)

Recommendation 17 — Evaluate NERC actions in the areas of cyber and physical security

The Critical Infrastructure Protection Committee shall evaluate the U.S.-Canada Power System Outage Task Force's Group III recommendations to determine if any actions are needed by NERC and report a proposed action plan to the board.

Action Plan

NERC will develop a mechanism to track all of the NERC, Task Force, and other reliability recommendations resulting from subsequent investigations of system disturbances and compliance reviews. Details of that plan are outside the scope of this report.

3. Complete Set of NERC Recommendations

This section consolidates all NERC recommendations, including the initial 14 recommendations approved in February 2004 and the four additional recommendations described above, into a single place.

Recommendation 1: Correct the Direct Causes of the August 14, 2003, Blackout.

The principal causes of the blackout were that FE did not maintain situational awareness of conditions on its power system and did not adequately manage tree growth in its transmission rights-of-way. Contributing factors included ineffective diagnostic support provided by MISO as the reliability coordinator for FE and ineffective communications between MISO and PJM.

NERC has taken immediate actions to ensure that the deficiencies that were directly causal to the August 14 blackout are corrected. These steps are necessary to assure electricity customers, regulators, and others with an interest in the reliable delivery of electricity that the power system is being operated in a manner that is safe and reliable, and that the specific causes of the August 14 blackout have been identified and fixed.

Recommendation 1a: FE, MISO, and PJM shall each complete the remedial actions designated in Attachment A for their respective organizations and certify to the NERC board no later than June 30, 2004, that these specified actions have been completed. Furthermore, each organization shall present its detailed plan for completing these actions to the NERC committees for technical review on March 23–24, 2004, and to the NERC board for approval no later than April 2, 2004.

Recommendation 1b: The NERC Technical Steering Committee shall immediately assign a team of experts to assist FE, MISO, and PJM in developing plans that adequately address the issues listed in Attachment A, and other remedial actions for which each entity may seek technical assistance.

Recommendation 2: Strengthen the NERC Compliance Enforcement Program.

NERC's analysis of the actions and events leading to the August 14 blackout leads it to conclude that several violations of NERC operating policies contributed directly to an uncontrolled, cascading outage on the Eastern Interconnection. NERC continues to investigate additional violations of NERC and regional reliability standards and will issue a final report of those violations once the investigation is complete.

In the absence of enabling legislation in the United States and complementary actions in Canada and Mexico to authorize the creation of an electric reliability organization, NERC lacks legally sanctioned authority to enforce compliance with its reliability rules. However, the August 14 blackout is a clear signal that voluntary compliance with reliability rules is no longer adequate. NERC and the regional reliability councils must assume firm authority to measure compliance, to more transparently report significant violations that could risk the integrity of the interconnected power system, and to take immediate and effective actions to ensure that such violations are corrected. Although all violations are important, a significant violation is one that could directly reduce the integrity of the interconnected power systems or otherwise cause unfavorable risk to the interconnected power systems. By contrast, a violation of a reporting or administrative requirement would not by itself generally be considered a significant violation.

Recommendation 2a: Each regional reliability council shall report to the NERC Compliance Enforcement Program within one month of occurrence all significant violations of NERC operating policies and planning standards and regional standards, whether verified or still under investigation. Such reports shall confidentially note details regarding the nature and potential reliability impacts of the alleged violations and the identity of parties involved. Additionally, each regional reliability council shall report quarterly to NERC, in a format prescribed by NERC, all violations of NERC and regional reliability council standards.

Recommendation 2b: When presented with the results of the investigation of any significant violation, and with due consideration of the surrounding facts and circumstances, the NERC board shall require an offending organization to correct the violation within a specified time. If the board determines that an offending organization is non-responsive and continues to cause a risk to the reliability of the interconnected power systems, the board will seek to remedy the violation by requesting assistance of the appropriate regulatory authorities in the United States, Canada, and Mexico.

Recommendation 2c: The Planning and Operating Committees, working in conjunction with the Compliance Enforcement Program, shall review and update existing approved and draft compliance templates applicable to current NERC operating policies and planning standards; and submit any revisions or new templates to the board for approval no later than March 31, 2004. To expedite this task, the NERC President shall immediately form a Compliance Template Task Force

comprised of representatives of each committee. The Compliance Enforcement Program shall issue the board-approved compliance templates to the regional reliability councils for adoption into their compliance monitoring programs.

This effort will make maximum use of existing approved and draft compliance templates in order to meet the aggressive schedule. The templates are intended to include all existing NERC operating policies and planning standards but can be adapted going forward to incorporate new reliability standards as they are adopted by the NERC board for implementation in the future.

Recommendation 2d: The NERC Compliance Enforcement Program and ECAR shall, within three months of the issuance of the final report from the Compliance and Standards investigation team, evaluate violations of NERC and regional standards, as compared to previous compliance reviews and audits for the applicable entities, and develop recommendations to improve the compliance process.

Recommendation 3: Initiate Control Area and Reliability Coordinator Reliability Readiness Audits.

In conducting its investigation, NERC found that deficiencies in control area and reliability coordinator capabilities to perform assigned reliability functions contributed to the August 14 blackout. In addition to specific violations of NERC and regional standards, some reliability coordinators and control areas were deficient in the performance of their reliability functions and did not achieve a level of performance that would be considered acceptable practice in areas such as operating tools, communications, and training. In a number of cases, there was a lack of clarity in the NERC policies with regard to what is expected of a reliability coordinator or control area. Although the deficiencies in the NERC policies must be addressed (see Recommendation 9), it is equally important to recognize that standards cannot prescribe all aspects of reliable operation and that minimum standards present a threshold, not a target for performance. Reliability coordinators and control areas must perform well, particularly under emergency conditions, and at all times strive for excellence in their assigned reliability functions and responsibilities.

Recommendation 3a: The NERC Compliance Enforcement Program and the regional reliability councils shall jointly establish a program to audit the reliability readiness of all reliability coordinators and control areas, with immediate attention given to addressing the deficiencies identified in the August 14 blackout investigation. Audits of all control areas and reliability coordinators shall be completed within three years and continue in a three-year cycle. The 20 highest priority audits, as determined by the Compliance Enforcement Program, will be completed by June 30, 2004.

Recommendation 3b: NERC will establish a set of baseline audit criteria to which regional criteria may be added. The control area requirements will be based on the existing NERC Control Area Certification Procedure. Reliability coordinator audits will include evaluation of reliability plans, procedures, processes, tools, personnel qualifications, and training. In addition to reviewing written documents, the audits will carefully examine the actual practices and preparedness of control areas and reliability coordinators.

Recommendation 3c: The reliability regions, with the oversight and direct participation of NERC, will audit each control area's and reliability coordinator's readiness to meet these audit criteria. FERC and other relevant regulatory agencies will be invited to participate in the audits, subject to the same confidentiality conditions as the other members of the audit teams.

Recommendation 4: Evaluate Vegetation Management Procedures and Results.

Ineffective vegetation management was a major cause of the August 14 blackout and also contributed to other historical large-scale blackouts, like the one that occurred on July 2–3, 1996, in the West. Maintaining transmission line rights-of-way (ROW), including maintaining safe clearances of energized lines from vegetation, under-build, and other obstructions incurs a substantial ongoing cost in many areas of North America. However, it is an important investment for assuring a reliable electric system. Vegetation, such as the trees that caused the initial line trips in FE that led to the August 14, 2003, outage is not the only type of obstruction that can breach the safe clearance distances from energized lines. Other examples include under-build of telephone and cable TV lines, train crossings, and even nests of certain large bird species.

NERC does not presently have standards for ROW maintenance. Standards on vegetation management are particularly challenging given the great diversity of vegetation and growth patterns across North America. However, NERC's standards do require that line ratings are calculated so as to maintain safe clearances from all obstructions. Furthermore, in the United States, the National Electrical Safety Code (NESC) Rules 232, 233, and 234 detail the minimum vertical and horizontal safety clearances of overhead conductors from grounded objects and various types of obstructions. NESC Rule 218 addresses tree clearances by simply stating, "Trees that may interfere with ungrounded supply conductors should be trimmed or removed." Several states have adopted their own electrical safety codes and similar codes apply in Canada.

Recognizing that ROW maintenance requirements vary substantially depending on local conditions, NERC will focus attention on measuring performance as indicated by the number of high-voltage line trips caused by vegetation. This approach has worked well in the Western Electricity Coordinating Council (WECC) since being instituted after the 1996 outages.

Recommendation 4a: NERC and the regional reliability councils shall jointly initiate a program to report all bulk electric system transmission line trips resulting from vegetation contact. The program will use the successful WECC vegetation monitoring program as a model.

A line trip includes a momentary opening and reclosing of the line, a lock out, or a combination. For reporting purposes, all vegetation-related openings of a line occurring within one 24-hour period should be considered one event. Trips known to be caused by severe weather or other natural disaster such as earthquake are excluded. Contact with vegetation includes both physical contact and arcing due to insufficient clearance.

All transmission lines operating at 230-kV and higher voltage, and any other lower voltage lines designated by the regional reliability council to be critical to the reliability of the bulk electric system, shall be included in the program.

Recommendation 4b: Beginning with an effective date of January 1, 2004, each transmission operator will submit an annual report of all vegetation-related high-voltage line trips to its respective reliability region. Each region shall assemble a detailed annual report of vegetation-related line trips in the region to NERC no later than March 31 for the preceding year, with the first reporting to be completed by March 2005 for calendar year 2004.

Vegetation management practices, including inspection and trimming requirements, can vary significantly with geography. Nonetheless, the events of August 14 and prior outages point to the need for independent verification that viable programs exist for ROW maintenance and that the programs are being followed.

Recommendation 4c: Each bulk electric transmission owner shall make its vegetation management procedure, and documentation of work completed, available for review and verification upon request by the applicable regional reliability council, NERC, or applicable federal, state, or provincial regulatory agency.

(NEW) Recommendation 4d: The Planning Committee, working with the Standards Authorization Committee, shall develop a measurable standard that specifies the minimum clearances between energized high voltage lines and vegetation. Appropriate criteria from the National Electrical Safety Code, or other appropriate code, should be adapted and interpreted so as to be applicable to vegetation.

Recommendation 5: Establish a Program to Track Implementation of Recommendations.

The August 14 blackout shared a number of contributing factors with prior large-scale blackouts, including:

- Conductors contacting trees
- Ineffective visualization of power system conditions and lack of situational awareness
- Ineffective communications
- Lack of training in recognizing and responding to emergencies
- Insufficient static and dynamic reactive power supply
- Need to improve relay protection schemes and coordination

It is important that recommendations resulting from system outages be adopted consistently by all regions and operating entities, not just those directly affected by a particular outage. Several lessons learned prior to August 14, if heeded, could have prevented the outage. WECC and NPCC, for example, have programs that could be used as models for tracking completion of recommendations. NERC and some regions have not adequately tracked completion of recommendations from prior events to ensure they were consistently implemented.

Recommendation 5a: NERC and each regional reliability council shall establish a program for documenting completion of recommendations resulting from the August 14 blackout and other historical outages, as well as NERC and regional reports on violations of reliability standards, results of compliance audits, and lessons learned from system disturbances.

Regions shall report quarterly to NERC on the status of follow-up actions to address recommendations, lessons learned, and areas noted for improvement. NERC staff shall report both NERC activities and a summary of regional activities to the board.

Recommendation 5b: NERC shall by January 1, 2005, establish a reliability performance monitoring function to evaluate and report bulk electric system reliability performance.

Assuring compliance with reliability standards, evaluating the reliability readiness of reliability coordinators and control areas, and assuring recommended actions are achieved will be effective steps in reducing the chances of future large-scale outages. However, it is important for NERC to also adopt a process for continuous learning and improvement by seeking continuous feedback on reliability performance trends, and not rely mainly on learning from and reacting to catastrophic failures.

Such a function would assess large-scale outages and near misses to determine root causes and lessons learned, similar to the August 14 blackout investigation. This function would incorporate the current Disturbance Analysis Working Group and expand that work to provide more proactive feedback to the NERC board regarding reliability performance. This program would also gather and analyze reliability performance statistics to inform the board of reliability trends. This function could develop procedures and capabilities to initiate investigations in the event of future large-scale outages or disturbances. Such procedures and capabilities would be shared between NERC and the regional reliability councils for use as needed, with NERC and regional investigation roles clearly defined in advance.

Recommendation 6: Improve Operator and Reliability Coordinator Training.

The investigation found that some reliability coordinators and control area operators had not received adequate training in recognizing and responding to system emergencies. Most notable was the lack of realistic simulations and drills for training and verifying the capabilities of operating personnel. This training deficiency contributed to the lack of situational awareness and failure to declare an emergency when operator intervention was still possible prior to the high-speed portion of the sequence of events.

Recommendation 6: All reliability coordinators, control areas, and transmission operators shall provide at least five days per year of training and drills in system emergencies, using realistic simulations, for each staff person with responsibility for the real-time operation or reliability monitoring of the bulk electric system. This system emergency training is in addition to other training requirements. Five days of system emergency training and drills are to be completed prior to June 30, 2004, with credit given for documented training already completed since July 1, 2003. Training documents, including curriculum, training methods, and individual training records, are to be available for verification during reliability readiness audits.

The term “realistic simulations” includes a variety of tools and methods that present operating personnel with situations to improve and test diagnostic and decision-making skills in an environment that resembles expected conditions during a particular type of system emergency. Although a full replica training simulator is one approach, lower cost alternatives such as PC-based simulators, tabletop drills, and simulated communications can be effective training aids if used properly.

NERC has published Continuing Education Criteria specifying appropriate qualifications for continuing education providers and training activities.

In the longer term, the NERC Personnel Certification Governance Committee (PCGC), which is independent of the NERC board, should explore expanding the certification requirements of system operating personnel to include additional measures of competency in recognizing and responding to system emergencies. The current NERC certification examination is a written test of the NERC Operating Manual and other references relating to operator job duties, and is not by itself intended to be a complete demonstration of competency to handle system emergencies.

Recommendation 7: Evaluate Reactive Power and Voltage Control Practices.

The blackout investigation identified inconsistent practices in northeastern Ohio with regard to the setting and coordination of voltage limits and insufficient reactive power supply. Although the deficiency of reactive power supply in northeastern Ohio did not directly cause the blackout, it was a contributing factor.

Planning Standard II.B.S1 requires each regional reliability council to establish procedures for generating equipment data verification and testing, including reactive power capability. Planning Standard III.C.S1

requires that all synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator. S2 of this standard also requires that generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units.

On one hand, the unsafe conditions on August 14 with respect to voltage in northeastern Ohio can be said to have resulted from violations of NERC planning criteria for reactive power and voltage control, and those violations should have been identified through the NERC and ECAR compliance monitoring programs (addressed by Recommendation 2). On the other hand, investigators believe reactive power and voltage control deficiencies noted on August 14 are also symptomatic of a systematic breakdown of the reliability studies and practices in FE and the ECAR region. As a result, unsafe voltage criteria were set and used in study models and operations. There were also issues identified with reactive characteristics of loads, as addressed in Recommendation 14.

Recommendation 7a: The Planning Committee shall reevaluate within one year the effectiveness of the existing reactive power and voltage control standards and how they are being implemented in practice in the ten NERC regions. Based on this evaluation, the Planning Committee shall recommend revisions to standards or process improvements to ensure voltage control and stability issues are adequately addressed.

Recommendation 7b: ECAR shall, no later than June 30, 2004, review its reactive power and voltage criteria and procedures, verify that its criteria and procedures are being fully implemented in regional and member studies and operations, and report the results to the NERC board.

Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.

The importance of automatic control and protection systems in preventing, slowing, or mitigating the impact of a large-scale outage cannot be stressed enough. To underscore this point, following the trip of the Sammis-Star line at 4:06, the cascading failure into parts of eight states and two provinces, including the trip of over 500 generating units and over 400 transmission lines, was completed in the next eight minutes. Most of the event sequence, in fact, occurred in the final 12 seconds of the cascade. Likewise, the July 2, 1996, failure took less than 30 seconds and the August 10, 1996, failure took only five minutes. It is not practical to expect operators will always be able to analyze a massive, complex system failure and to take the appropriate corrective actions in a matter of a few minutes. The NERC investigators believe that two measures would have been crucial in slowing or stopping the uncontrolled cascade on August 14:

- Better application of zone 3 impedance relays on high-voltage transmission lines
- Selective use of under-voltage load shedding.

First, beginning with the Sammis-Star line trip, many of the remaining line trips during the cascade phase were the result of the operation of a zone 3 relay for a perceived overload (a combination of high amperes and low voltage) on the protected line. If used, zone 3 relays typically act as an overreaching backup to the zone 1 and 2 relays, and are not intentionally set to operate on a line overload. However, under extreme conditions of low voltages and large power swings as seen on August 14, zone 3 relays can operate for overload conditions and propagate the outage to a wider area by essentially causing the system to “break up”. Many of the zone 3 relays that operated during the August 14 cascading outage were not set with adequate margins above their emergency thermal ratings. For the short times involved, thermal

heating is not a problem and the lines should not be tripped for overloads. Instead, power system protection devices should be set to address the specific condition of concern, such as a fault, out-of-step condition, etc., and should not compromise a power system's inherent physical capability to slow down or stop a cascading event.

Recommendation 8a: All transmission owners shall, no later than September 30, 2004, evaluate the zone 3 relay settings on all transmission lines operating at 230-kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions. In each case that a zone 3 relay is set so as to trip on load under extreme conditions, the transmission operator shall reset, upgrade, replace, or otherwise mitigate the overreach of those relays as soon as possible and on a priority basis, but no later than December 31, 2005. Upon completing analysis of its application of zone 3 relays, each transmission owner may, no later than December 31, 2004, submit justification to NERC for applying zone 3 relays outside of these recommended parameters. The Planning Committee shall review such exceptions to ensure they do not increase the risk of widening a cascading failure of the power system.

The investigation team recommends that the zone 3 relay, if used, should not operate at or below 150 percent of the emergency ampere rating of a line, assuming a .85 per unit voltage and a line phase angle of 30 degrees.

A second key conclusion with regard to system protection was that if an automatic under-voltage load shedding scheme had been in place in the Cleveland-Akron area on August 14, there is a high probability the outage could have been limited to that area.

Recommendation 8b: Each regional reliability council shall complete an evaluation of the feasibility and benefits of installing under-voltage load shedding capability in load centers within the region that could become unstable as a result of being deficient in reactive power following credible multiple-contingency events. The regions are to complete the initial studies and report the results to NERC within one year. The regions are requested to promote the installation of under-voltage load shedding capabilities within critical areas, as determined by the studies to be effective in preventing an uncontrolled cascade of the power system.

The NERC investigation of the August 14 blackout has identified additional transmission and generation control and protection issues requiring further analysis. One concern is that generating unit control and protection schemes need to consider the full range of possible extreme system conditions, such as the low voltages and low and high frequencies experienced on August 14. The team also noted that improvements may be needed in underfrequency load shedding and its coordination with generator under and over-frequency protection and controls.

Recommendation 8c: The Planning Committee shall evaluate Planning Standard III — System Protection and Control and propose within one year specific revisions to the criteria to adequately address the issue of slowing or limiting the propagation of a cascading failure. The board directs the Planning Committee to evaluate the lessons from August 14 regarding relay protection design and application and offer additional recommendations for improvement.

Recommendation 9: Clarify Reliability Coordinator and Control Area Functions, Responsibilities, Capabilities, and Authorities.

Ambiguities in the NERC operating policies may have allowed entities involved in the August 14 blackout to make different interpretations regarding the functions, responsibilities, capabilities, and

authorities of reliability coordinators and control areas. Characteristics and capabilities necessary to enable prompt recognition and effective response to system emergencies must be specified.

The lack of timely and accurate outage information resulted in degraded performance of state estimator and reliability assessment functions on August 14. There is a need to review options for sharing of outage information in the operating time horizon (e.g., 15 minutes or less), so as to ensure the accurate and timely sharing of outage data necessary to support real-time operating tools such as state estimators, real-time contingency analysis, and other system monitoring tools.

On August 14, reliability coordinator and control area communications regarding conditions in northeastern Ohio were ineffective, and in some cases confusing. Ineffective communications contributed to a lack of situational awareness and precluded effective actions to prevent the cascade. Consistent application of effective communications protocols, particularly during emergencies, is essential to reliability. Alternatives should be considered to one-on-one phone calls during an emergency to ensure all parties are getting timely and accurate information with a minimum number of calls.

NERC operating policies do not adequately specify critical facilities, leaving ambiguity regarding which facilities must be monitored by reliability coordinators. Nor do the policies adequately define criteria for declaring transmission system emergencies. Operating policies should also clearly specify that curtailing interchange transactions through the NERC TLR procedure is not intended to be used as a method for restoring the system from an actual Operating Security Limit violation to a secure operating state.

The Operating Committee shall complete the following by June 30, 2004:

- Evaluate and revise the operating policies and procedures, or provide interpretations, to ensure reliability coordinator and control area functions, responsibilities, and authorities are completely and unambiguously defined.
- Evaluate and improve the tools and procedures for operator and reliability coordinator communications during emergencies.
- Evaluate and improve the tools and procedures for the timely exchange of outage information among control areas and reliability coordinators.

Recommendation 10: Establish Guidelines for Real-Time Operating Tools.

The August 14 blackout was caused by a lack of situational awareness that was in turn the result of inadequate reliability tools and backup capabilities. Additionally, the failure of the FE control computers and alarm system contributed directly to the lack of situational awareness. Likewise, MISO's incomplete tool set and the failure of its state estimator to work effectively on August 14 contributed to the lack of situational awareness.

Recommendation 10: The Operating Committee shall, within one year, evaluate the real-time operating tools necessary for reliable operation and reliability coordination, including backup capabilities. The Operating Committee is directed to report both minimum acceptable capabilities for critical reliability functions and a guide of best practices.

This evaluation should include consideration of the following:

- Modeling requirements, such as model size and fidelity, real and reactive load modeling, sensitivity analyses, accuracy analyses, validation, measurement, observability, update procedures, and procedures for the timely exchange of modeling data.

- State estimation requirements, such as periodicity of execution, monitoring external facilities, solution quality, topology error and measurement error detection, failure rates including times between failures, presentation of solution results including alarms, and troubleshooting procedures.
- Real-time contingency analysis requirements, such as contingency definition, periodicity of failure execution, monitoring external facilities, solution quality, post-contingency automatic actions, rates including mean/maximum times between failures, reporting of results, presentation of solution results including alarms, and troubleshooting procedures including procedures for investigating non-converging contingency studies.

Recommendation 11: Evaluate Lessons Learned During System Restoration.

The efforts to restore the power system and customer service following the outage were effective, considering the massive amount of load lost and the large number of generators and transmission lines that tripped. Fortunately, the restoration was aided by the ability to energize transmission from neighboring systems, thereby speeding the recovery. Despite the apparent success of the restoration effort, it is important to evaluate the results in more detail to determine opportunities for improvement. Blackstart and restoration plans are often developed through study of simulated conditions. Robust testing of live systems is difficult because of the risk of disturbing the system or interrupting customers. The August 14 blackout provides a valuable opportunity to apply actual events and experiences to learn to better prepare for system blackstart and restoration in the future. That opportunity should not be lost, despite the relative success of the restoration phase of the outage.

Recommendation 11a: The Planning Committee, working in conjunction with the Operating Committee, NPCC, ECAR, and PJM, shall evaluate the blackstart and system restoration performance following the outage of August 14, and within one year report to the NERC board the results of that evaluation with recommendations for improvement.

Recommendation 11b: All regional reliability councils shall, within six months of the Planning Committee report to the NERC board, reevaluate their procedures and plans to assure an effective blackstart and restoration capability within their region.

Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed.

A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices.

NERC Planning Standard I.F — Disturbance Monitoring does require location of recording devices for disturbance analysis. Often time, recorders are available, but they are not synchronized to a time standard. All digital fault recorders, digital event recorders, and power system disturbance recorders should be time stamped at the point of observation with a precise Global Positioning Satellite (GPS) synchronizing signal. Recording and time-synchronization equipment should be monitored and calibrated to assure accuracy and reliability.

Time-synchronized devices, such as phasor measurement units, can also be beneficial for monitoring a wide-area view of power system conditions in real-time, such as demonstrated in WECC with their Wide-Area Monitoring System (WAMS).

Recommendation 12a: The reliability regions, coordinated through the NERC Planning Committee, shall within one year define regional criteria for the application of synchronized recording devices in power plants and substations. Regions are requested to facilitate the installation of an appropriate number, type, and location of devices within the region as soon as practical to allow accurate recording of future system disturbances and to facilitate benchmarking of simulation studies by comparison to actual disturbances.

Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization and, as necessary, install additional dynamic recorders.

Recommendation 13: Reevaluate System Design, Planning, and Operating Criteria.

The investigation report noted that FE entered the day on August 14 with insufficient resources to stay within operating limits following a credible set of contingencies, such as the loss of the Eastlake 5 unit and the Chamberlin-Harding line. NERC will conduct an evaluation of operations planning practices and criteria to ensure expected practices are sufficient and well understood. The review will reexamine fundamental operating criteria, such as n-1 and the 30-minute limit in preparing the system for a next contingency, and Table I Category C.3 of the NERC planning standards. Operations planning and operating criteria will be identified that are sufficient to ensure the system is in a known and reliable condition at all times, and that positive controls, whether manual or automatic, are available and appropriately located at all times to return the Interconnection to a secure condition. Daily operations planning, and subsequent real-time operations planning will identify available system reserves to meet operating criteria.

Recommendation 13a: The Operating Committee shall evaluate operations planning and operating criteria and recommend revisions in a report to the board within one year.

Prior studies in the ECAR region did not adequately define the system conditions that were observed on August 14. Severe contingency criteria were not adequate to address the events of August 14 that led to the uncontrolled cascade. Also, northeastern Ohio was found to have insufficient reactive support to serve its loads and meet import criteria. Instances were also noted in the FE system and ECAR area of different ratings being used for the same facility by planners and operators and among entities, making the models used for system planning and operation suspect. NERC and the regional reliability councils must take steps to assure facility ratings are being determined using consistent criteria and being effectively shared and reviewed among entities and among planners and operators.

Recommendation 13b: ECAR shall, no later than June 30, 2004, reevaluate its planning and study procedures and practices to ensure they are in compliance with NERC standards, ECAR Document No. 1, and other relevant criteria; and that ECAR and its members' studies are being implemented as required.

Recommendation 13c: The Planning Committee, working in conjunction with the regional reliability councils, shall within two years reevaluate the criteria, methods, and practices used for system design, planning, and analysis; and shall report the results and recommendations to the NERC board. This review shall include an evaluation of transmission facility ratings methods and practices, and the sharing of consistent ratings information.

Regional reliability councils may consider assembling a regional database that includes the ratings of all bulk electric system (100-kV and higher voltage) transmission lines, transformers, phase angle regulators,

and phase shifters. This database should be shared with neighboring regions as needed for system planning and analysis.

NERC and the regional reliability councils should review the scope, frequency, and coordination of interregional studies, to include the possible need for simultaneous transfer studies. Study criteria will be reviewed, particularly the maximum credible contingency criteria used for system analysis. Each control area will be required to identify, for both the planning and operating time horizons, the planned emergency import capabilities for each major load area.

Recommendation 14: Improve System Modeling Data and Data Exchange Practices.

The after-the-fact models developed to simulate August 14 conditions and events indicate that dynamic modeling assumptions, including generator and load power factors, used in planning and operating models were inaccurate. Of particular note, the assumptions of load power factor were overly optimistic (loads were absorbing much more reactive power than pre-August 14 models indicated). Another suspected problem is modeling of shunt capacitors under depressed voltage conditions. Regional reliability councils should establish regional power system models that enable the sharing of consistent, validated data among entities in the region. Power flow and transient stability simulations should be periodically compared (benchmarked) with actual system events to validate model data. Viable load (including load power factor) and generator testing programs are necessary to improve agreement between power flows and dynamic simulations and the actual system performance.

Recommendation 14: The regional reliability councils shall, within one year, establish and begin implementing criteria and procedures for validating data used in power flow models and dynamic simulations by benchmarking model data with actual system performance. Validated modeling data shall be exchanged on an interregional basis as needed for reliable system planning and operation.

(NEW) Recommendation 15: Develop a standing capability for NERC to investigate future blackouts and disturbances.

NERC shall develop and be prepared to implement a NERC standing procedure for investigating future blackouts and system disturbances. Many of the methods, tools, and lessons from the investigation of the August 14 blackout are appropriate for adoption.

(NEW) Recommendation 16: Accelerate the standards transition.

NERC shall accelerate the transition from existing operating policies, planning standards, and compliance templates to a clear and measurable set of reliability standards. (This recommendation is consistent with the Task Force recommendation 25).

(NEW) Recommendation 17 — Evaluate NERC actions in the areas of cyber and physical security.

The Critical Infrastructure Protection Committee shall evaluate the U.S.-Canada Power System Outage Task Force's Group III recommendations to determine if any actions are needed by NERC and report a proposed action plan to the board.

4. Specific Actions Directed to FE, MISO, and PJM

Corrective Actions to be Completed by FirstEnergy

FE shall complete the following corrective actions by June 30, 2004. Unless otherwise stated, the requirements apply to the FE northern Ohio system and connected generators.

1. Voltage Criteria and Reactive Resources

- a. **Interim Voltage Criteria.** The investigation team found that FE was not operating on August 14 within NERC planning and operating criteria with respect to its voltage profile and reactive power supply margin in the Cleveland-Akron area. FE was also operating outside its own historical planning and operating criteria that were developed and used by Centerior Energy Corporation (The Cleveland Electric Illuminating Company and the Toledo Edison Company) prior to 1998 to meet the relevant NERC and ECAR standards and criteria. FE stated acceptable ranges for voltage are not compatible with neighboring systems or interconnected systems in general.

Until such time that the study of the northern Ohio system ordered by the Federal Energy Regulatory Commission (FERC) on December 23 is completed, and until FE is able to determine (in b. below) a current set of voltage and reactive requirements verified to be within NERC and ECAR criteria, FE shall immediately operate such that voltages at all 345-kV buses in the Cleveland-Akron area shall have a minimum voltage of .95 per unit following the simultaneous loss of the two largest generating units in that area.

- b. **Calculation of Minimum Bus Voltages and Reactive Reserves.** FE shall, consistent with or as part of the FERC-ordered study, determine the minimum location-specific voltages at all 345-kV and 138-kV buses and all generating stations within their control area (including merchant plants). FE shall determine the minimum dynamic reactive reserves that must be maintained in local areas to ensure that these minimum voltages are met following contingencies studied in accordance with ECAR Document 1. Criteria and minimum voltage requirements must comply with NERC planning criteria, including Table 1A, Category C3, and Operating Policy 2.
- c. **Voltage Procedures.** FE shall determine voltage and reactive criteria and procedures to enable operators to understand and operate these criteria.
- d. **Study Results.** When the FERC-ordered study is completed, FE is to adopt the planning and operating criteria determined as a result of that study and update the operating criteria and procedures for its system operators. If the study indicates a need for system reinforcements, FE shall develop a plan for developing such reinforcements as soon as practical, and shall develop operational procedures or other mitigating programs to maintain safe operating conditions until such time that the necessary system reinforcements can be made.
- e. **Reactive Resources.** FE shall inspect all reactive resources, including generators, and assure that all are fully operational. FE shall verify that all installed capacitors have no blown fuses and that at least 98 percent of installed capacitors at 69-kV and higher are available and in service during the summer 2004.
- f. **Communications.** FE shall communicate its voltage criteria and procedures, as described in the items above to MISO and FE neighboring systems.

2. Operational Preparedness and Action Plan

The FE 2003 Summer Assessment was not considered to be sufficiently comprehensive to cover a wide range of known and expected system conditions, nor effective for the August 14 conditions based on the following:

- No voltage stability assessment was included to assess the Cleveland-Akron area which has a long-known history of potential voltage collapse, as indicated CEI studies prior to 1997, by non-convergence of power flow studies in the 1998 analysis, and advice from AEP of potential voltage collapse prior to the onset of the 2003 summer load period.
- Only single contingencies were tested for basically one set of 2003 study conditions. This does not comply with the study requirements of ECAR Document 1.
- Study conditions should have assumed a wider range of generation dispatch and import/export and interregional transfers. For example, imports from MECS (north-to-south transfers) are likely to be less stressful to the FE system than imports from AEP (south-to-north transfers). Sensitivity studies should have been conducted to assess the impact of each key parameter and derive the system operating limits accordingly based on the most limiting of transient stability, voltage stability, and thermal capability.
- The 2003 study conditions are considered to be more onerous than those assumed in the 1998 study, since the former has Davis Besse (830 MW) as a scheduled outage. However, the 2003 study does not show any voltage instability problems as shown by the 1998 study.
- The 2003 study conditions are far less onerous than the actual August 14 conditions from the generation and transmission availability viewpoint. This is another indication that n-1 contingency assessment, based on one assumed system condition, is not sufficient to cover the variability of changing system conditions due to forced outages.

FE shall prepare and submit to ECAR, with a copy to NERC, an Operational Preparedness and Action Plan to ensure system security and full compliance with NERC and [regional] planning and operating criteria, including ECAR Document 1. The action plan shall include, but not be limited to the following:

- a. **2004 Summer Studies.** Complete a 2004 summer study to identify a comprehensive set of System Operating Limits (OSL) and Interconnection Reliability Limits (IRLs) based on the NERC Operating Limit Definition Task Force Report. Any inter-dependency between FE OSL and those of its neighboring entities, known and forecasted regional and interregional transfers, shall be included in the derivation of OSL and IRL.
- b. **Extreme Contingencies.** Identify high-risk contingencies that are beyond normal studied criteria and determine the performance of the system for these contingencies. Where these extreme contingencies result in cascading outages, determine means to reduce their probability of occurrence or impact. These contingencies and mitigation plans must be communicated to FE operators, ECAR, MISO, and neighboring systems.
- c. **Maximum Import Capability.** Determine the maximum import capability into the Cleveland-Akron area for the summer of 2004, consistent with the criteria stated in (1) above and all applicable NERC and ECAR criteria. The maximum import capability shall take into account historical and forecasted transactions and outage conditions expected with due regard to maintaining adequate operating and local dynamic reactive reserves.

- d. **Vegetation Management.** FE was found to not be complying with its own procedures for rights-of-way maintenance and was not adequately resolving inspection and forced outage reports indicating persistent problems with vegetation contacts prior to August 14, 2003. FE shall complete rights-of-way trimming for all 345-kV and 138-kV transmission lines, so as to be in compliance with the National Electrical Safety Code criteria for safe clearances for overhead conductors, other applicable federal, state and local laws, and FE rights-of-way maintenance procedures. Priority should be placed on completing work for all 345-kV lines as soon as possible. FE will report monthly progress to NERC and ECAR.
- e. **Line Ratings.** FE shall reevaluate its criteria for calculating line ratings, survey the 345-kV, and 138-kV rights-of-way by visual inspection to ensure line ratings are appropriate for the clearances observed, and calculate updated ratings for each line. FE shall ensure that system operators, MISO, ECAR, NERC (MMWG), and neighboring systems are informed of and able to use the updated line ratings.

3. Emergency Response Capabilities and Preparedness

- a. **Emergency Response Resources.** FE shall develop a capability, no later than June 30, 2004, to reduce load in the Cleveland-Akron area by 1,500 MW within ten minutes of a directive to do so by MISO or the FE system operator. Such a capability may be provided by automatic or manual load shedding, voltage reduction, direct-controlled commercial or residential load management, or any other method or combination of methods capable of achieving the 1,500 MW of reduction in ten minutes without adversely affecting other interconnected systems. The amount of required load reduction capability may be reduced to an amount shown by the FERC-ordered study to be sufficient for response to severe contingencies and if approved by ECAR and NERC.
- b. **Emergency Response Plan.** FE shall develop emergency response plans, including plans to deploy the load reduction capabilities noted above. The plan shall include criteria for declaring an emergency and various states of emergency. The plan shall include detailed descriptions of authorities, operating procedures, and communication protocols with all the relevant entities including MISO, FE operators, and market participants within the FE area that have the ability to move generation or shed load upon orders from FE operators. The plan shall include procedures for load restoration after the declaration that the FE system is no longer in the emergency operating state.

4. Operating Center and Training

- a. **Operator Communications.** FE shall develop communications procedures for FE operating personnel to use within FE, with MISO and neighboring systems, and others. The procedure and the operating environment within the FE system control center shall allow focus on reliable system operation and avoid distractions such as calls from customers and others who are not responsible for operation of a portion of the transmission system.
- b. **Reliability Monitoring Tools.** FE shall ensure its state estimation and real-time contingency analysis functions are being used to reliably execute full contingency analysis automatically every ten minutes, or on demand, and to alarm operators of potential first contingency violations.
- c. **System Visualization Tools.** FE shall provide its operating personnel with the capability to visualize the status of the power system from an overview perspective and to determine critical system failures or unsafe conditions quickly without multiple-step searches for failures. A dynamic map board or equivalent capability is encouraged.

- d. **Backup Functions and Center.** FE shall develop and prepare to implement a plan for the loss of its system operating center or any portion of its critical operating functions. FE shall comport with the criteria of the NERC Reference Document — Back Up Control Centers, and ensure that FE is able to continue meeting all NERC and ECAR criteria in the event the operating center becomes unavailable. Consideration should be given to using capabilities at MISO or neighboring systems as a backup capability, at least for summer 2004, until alternative backup functionality can be provided.
- e. **GE XA21 System Updates.** Until the current energy management system is replaced, FE shall incorporate all fixes for the GE XA21 system known to be necessary to assure reliable and stable operation of critical reliability functions, and particularly to correct the alarm processor failure that occurred on August 14, 2003.
- f. **Operator Training.** Prior to June 30, 2004, FE shall meet the operator training requirements detailed in NERC Recommendation 6.
- g. **Technical Support.** FE shall develop and implement a written procedure describing the interactions between control center technical support personnel and system operators. The procedure shall address notification of loss of critical functionality and testing procedures.

5. Corrective Actions to be Completed by MISO

MISO shall complete the following corrective actions no later than June 30, 2004.

- 1. **Reliability Tools.** MISO shall fully implement and test its topology processor to provide its operating personnel real-time view of the system status for all transmission lines operating and all generating units within its system, and all critical transmission lines and generating units in neighboring systems. Alarms should be provided for operators for all critical transmission line outages. MISO shall establish a means of exchanging outage information with its members and neighboring systems such that the MISO state estimation has accurate and timely information to perform as designed. MISO shall fully implement and test its state estimation and real-time contingency analysis tools to ensure they can operate reliably no less than every ten minutes. MISO shall provide backup capability for all functions critical to reliability.
- 2. **Visualization Tools.** MISO shall provide its operating personnel with tools to quickly visualize system status and failures of key lines, generators, or equipment. The visualization shall include a high-level voltage profile of the systems at least within the MISO footprint.
- 3. **Training.** Prior to June 30, 2004, MISO shall meet the operator training criteria stated in NERC Recommendation 6.
- 4. **Communications.** MISO shall reevaluate and improve its communications protocols and procedures with operational support personnel within MISO, its operating members, and its neighboring control areas and reliability coordinators.
- 5. **Operating Agreements.** MISO shall reevaluate its operating agreements with member entities to verify its authority to address operating issues, including voltage and reactive management, voltage scheduling, the deployment and redispatch of real and reactive reserves for emergency response, and the authority to direct actions during system emergencies, including shedding load.

6. Corrective Actions to be Completed by PJM

PJM shall complete the following corrective actions no later than June 30, 2004.

Communications. PJM shall reevaluate and improve its communications protocols and procedures between PJM and its neighboring reliability coordinators and control areas.